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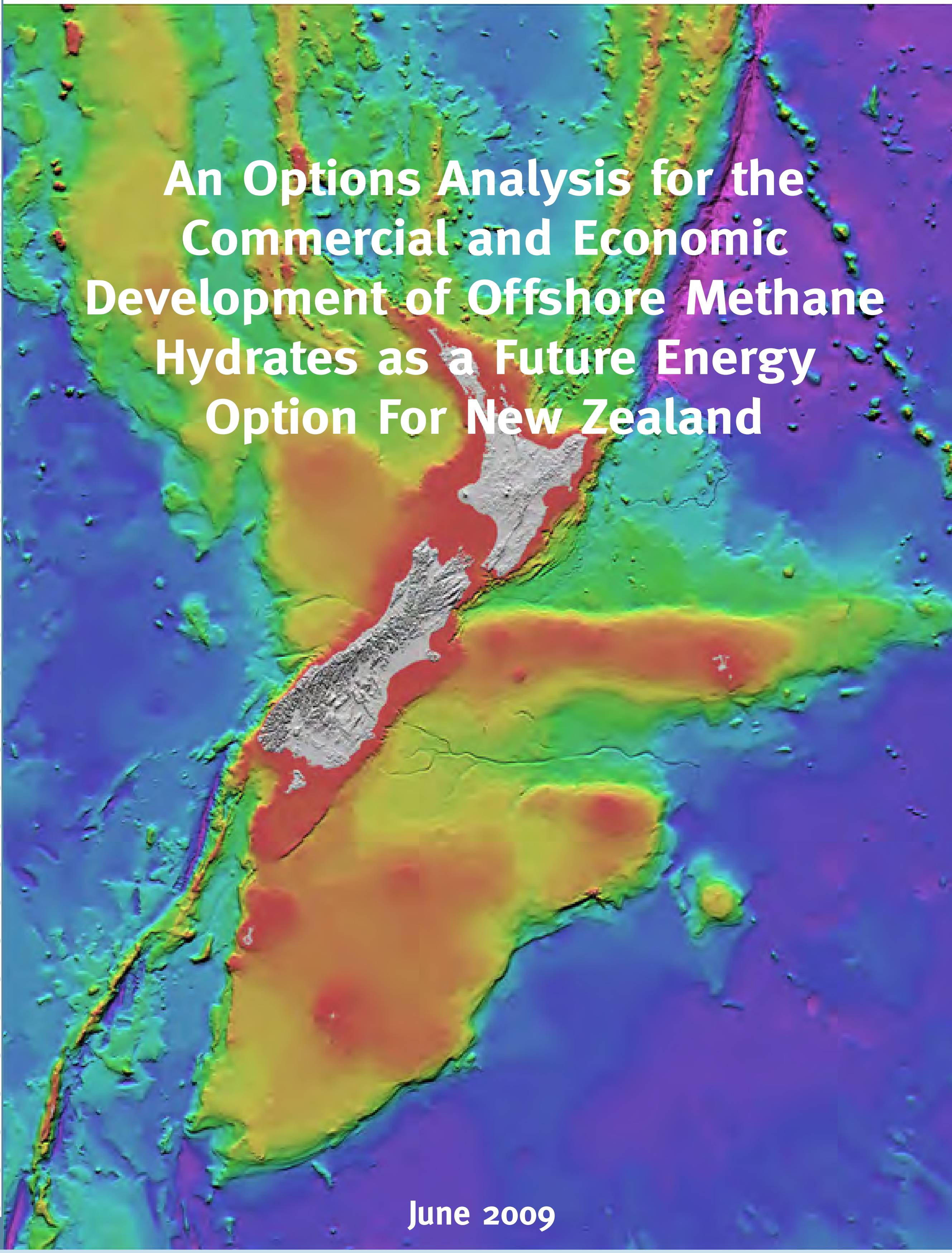

An Options Analysis for the Commercial and Economic Development of Offshore Methane Hydrates as a Future Energy Option For New Zealand

June 2009

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An Options Analysis for the Commercial and Economic Development of Offshore Methane Hydrates as a Future Energy Option For New Zealand

Prepared for

Crown Minerals Group
Ministry For Economic Development

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39 Creyke Road, Private Bag 4800

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23rd June 2009

Disclaimer

This report represents solely the views and opinions of the CAENZ Study Team, and has been generated independently of the Client and the contributors to this study. The conclusions and recommendations for the way forward sections of this report do not represent the views of the Institute of Geological and Nuclear Sciences Limited, the National Institute of Water and Atmospheric Research Limited, The Client or the other contributors.

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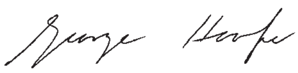

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GLOSSARY

BAU	Business As Usual
BGHS	Base Gas Hydrate Stability Zone
Bm^3	Billion cubic metres
BSR	Bottom Stimulating Reflectors
CIF	Cost Including Freight (trade term)
CM	The Crown Minerals Group, Ministry for Economic Development, New Zealand
CBM	Coal Bed Methane aka Coal Seam Methane
CSM	Coal Seam Methane aka Coal Bed Methane
CSEM	Controlled Source Electromagnetic Marine Survey Technology
CSS	Carbon Capture and Sequenstration
ERR	Economically Recoverable Resources (Gas Hydrate)
FOB	Free On Board (trade term)
FPU	Floating Production Unit
GJ	Giga Joule
GNS	The Institute of Geological and Nuclear Sciences, New Zealand
IRR	Internal Rate of Return
JAPEX	Japan Petroleum Exploration Corporation
JIP	Joint Industry Programme
JNOC	Japan National Oil Corporation
JOGMEC	Japan Oil, Gas and Metals National Corporation
KNOC	South Korea National Oil Corporation
LDHI	Low Dose Hydrate Inhibitor
LNG	Liquefied Natural Gas
mbsl	Metres Below Sea Level
MED	Ministry for Economic Development, New Zealand
MH21	Research Consortium for Methane Hydrates Research In Japan, incorporating Japan Oil, Gas and Metals National Corporation (JOGMEC), the National Institute of Advanced Industrial Science and Technology (AIST), and the Engineering Advancement Association of Japan (ENAA)
MHAC	Methane Hydrates Advisory Council, United States of America
MITI	Ministry of International Trade and Investment, Japan
MMtpa	Million Metric Tonne Per Annum
MMscf/d	Million Standard Cubic Feet per day
NETL	National Energy Technology Laboratory, US Department of Energy
NIWA	The National Institute for Water and Atmospheric Research, New Zealand
NRC	National Resources Canada
ONGC	Oil and Natural Gas Corporation, India
PJ	Peta Joule
QGC	An Australian coal seam gas explorer and producer, with developments that include Queensland's Curtis LNG project
SPAR	Floating oil platform typically used in very deep waters.
Tcf	Trillion cubic feet (1 tcf=0.02832 tm^3)
TLP	Tension Leg Platform
Tm^3	Trillion cubic metres (1 tm^3=35.3146 tcf)
TRR	Technically Recoverable Resources (Gas Hydrate)
USGS	United States Geological Survey
US DoE	United States Department of Energy
WEC	World Energy Council

EXECUTIVE SUMMARY

Methane hydrates within the bed of the deep continental shelf margin offshore of New Zealand comprise a significant component of our natural resources endowment.

To date, the importance and potential value of this resource has been largely ignored in New Zealand. However, the rapid advancement in global knowledge and understanding of marine methane hydrate resources, and the development of technology to derive energy from it, strongly suggests that the prospectivity of the hydrates resource needs to be properly assessed and appraised if we are to maximise the overall national benefits to New Zealand of its natural resource estate.

This advancement in knowledge has been derived principally from the hydrates exploration and research programmes of nations such as the U.S. and Canada in particular, as well as more recently India, China and South Korea, who are following the early leadership of Japan, and from the significant scientific contributions of other developed nations in North America and Europe.

New Zealand is differentiated from these countries by the smaller size of our population and economy. However, this country's methane hydrates endowment is potentially one of the largest in the world and very likely, the largest on a per capita or per unit of GDP basis.

Commercial development of this resource will rely on practical technologies for the recovery of marine methane hydrate to be proven, and optimised for application in New Zealand conditions. Once this goal is attained, development of this resource opportunity will be able to more than adequately fulfil our domestic requirements for natural gas; and in addition, could form the basis for major new export industry.

The research basis for an accelerated programme of investigation towards the commercial development of New Zealand's marine hydrate resources is surprisingly strong, considering the limited funding allocated over the past decade or so. GNS Science, together with NIWA and University of Otago geoscientists, have effectively leveraged relationships with some of the strongest international research groups to develop a preliminary understanding of the mode of occurrence of methane hydrate in the sea bed of the Hikurangi (eastern North Island) and Fiordland (western South Island margins). This research base will, however, need to be intensified considerably before serious work on resource development can be undertaken.

In this study, we have synthesised the current state of scientific knowledge and international learning to develop a possible road map for the commercial production of methane hydrate in New Zealand. This road map anticipates that continuing rapid progress in the engineering geology and production technologies required for hydrates extraction, both internationally and in New Zealand, that will allow the commercial production of energy from marine hydrate to become realisable in the near-to-medium term. The likelihood of this timeframe being achieved and the economic value that is attributable to the hydrate opportunity justifies, we believe, a considerable ramp-up of hydrate research in this country, as well as a targeted investigative and development effort designed to ensure that New Zealand has the earliest possible opportunity to develop its marine hydrate resources.

Potential benefits of New Zealand leadership in marine hydrate development include the following:

- Indigenous gas hydrate development could prove preferable to LNG importation as a "backstop" thermal fuel for electricity generation and direct use, should exploration fall short of sustaining conventional and other unconventional gas supplies;
- Development could be on a scale that would exceed New Zealand's own requirements and underpin new or other alternative industries that would generate substantial export revenues; e.g. LNG exports;

- Abundant energy would restore the competitive advantage of value-adding manufacturing industries, including petrochemicals, in New Zealand by lowering current energy tariffs;
- New Zealand would develop a world-leading skilled service industry for marine gas hydrate development.

A conceptual hydrates well development plan for a prospective Wairarapa 'sweet spot' site offshore of the Wairarapa cost of the lower eastern North Island, prepared by Transfield Worley Services specifically for this study, has provided a robust overview of the likely scale of costs to develop the marine hydrates resource opportunity. While significantly high relative to conventional gas developments at present, these costs are likely to reduce over time as new technologies are developed or existing conventional technologies are optimised.

However, the purpose of the study has not been simply to provide an economic case for investment in hydrate development. More importantly, we have sought to establish the likely benefits that will flow to New Zealand from a national investment in improving the prospectively of the county's continental shelf region and it's petroleum resources. We should not lose sight of the value that can be ascribed to an improved and diverse energy reserves position and the security of fuel supply that would derive from this.

In this study, we have assessed a national staged gas hydrates development producing 150 PJ/year natural gas as an alternative to imported or indigenous fuel. When compared against imported LNG, the cost-benefit analysis indicates a significant net economic benefit under the base case assumptions used.

Accelerating the development of the hydrates resources could significantly reduce the long term economic cost of supplying gas to the New Zealand market. Extending this case to 300 PJ/year offers a potentially viable export gas option.

This study recommends that government develop and implement a strategic programme to bring forward assessment of the gas hydrates resource and put in place the necessary studies to allow the ongoing evaluation of the business case for gas hydrate development. Moving forward, however, requires that New Zealand fully assess all options available to it and not just gas hydrates. CAENZ has previously argued for a separate agency responsible for procuring and undertaking the necessary investigations to maximise the value of indigenous resources and to ensure that commercial exploitation of these resources are fully aligned with the national interest.

This study reinforces the case for the establishment of such an entity and suggests that New Zealand could be at the forefront of investigation of this frontier resource opportunity. Further advancement of the New Zealand hydrates opportunity will offer an important contribution to technology and science capacity in this country, as well as offering a transformational opportunity for the New Zealand resource sectors.

1 INTRODUCTION

1.1. Background

This report aims to provide an objective, independent and 'over-the-horizon' perspective on the potential economic benefits to New Zealand that might arise from commercial development of its substantial methane gas hydrates resource, and the options available to the country to more effectively leverage present expertise to build greater indigenous capacity in this field.

In bringing this perspective together, the study team gave particular emphasis to learning from international experience, and during the course of the study initiated a number of international visits from recognised leaders in the field, as well as contributing towards multi-stakeholder initiatives intended to help with building ongoing research relationships and capability.

A desired additional outcome of the study is to facilitate participation by New Zealand research institutes in international joint ventures and collaborations, and to encourage the participation of New Zealand industry players in any future national effort to extend our knowledge of the resource.

In this report we examine the status of our knowledge of New Zealand's gas hydrate deposits, and the practicalities of their extraction and production. Through the engagement with industry players and the contributions made by our international visitors, we have also sought to identify critical gaps in our knowledge base and opportunities for future alignment of New Zealand activity with international hydrate exploration and development efforts.

The study reports an options analysis that provides a possible road map for the commercial production of gas hydrate in New Zealand, the preferred arrangements between industry, government and the research sector that would allow for the optimal realisation of the economic potential of the resource, and the likely economic benefits that would flow to New Zealand from commercialisation of the resource.

1.2 Methane Hydrates

In this report, we consider methane hydrates as possibly New Zealand's next major energy resource. Chemically, methane stored as hydrates is no different to other methane resources such as those found in free gas reservoirs and coal seams. It was the discovery of naturally occurring hydrate beneath the Siberian permafrost in 1969 that opened up the possibilities of their potential as an energy resource. Since that time, a growing awareness of gas hydrates has prompted many of the world's leading economies to actively engage in research. Hundreds of millions of dollars have been spent in international efforts to survey, characterize and produce gas from hydrate deposits (MHAC 2007[1]).

1 US Federal Methane Hydrates Advisory Committee (MHAC) 2007. Report to Congress – An Assessment of the Methane Hydrate Research Program and An Assessment of the 5-Year Research Plan of the Department of Energy.

Figure 1.1: Examples of Methane Hydrates (from Pierce 2008)

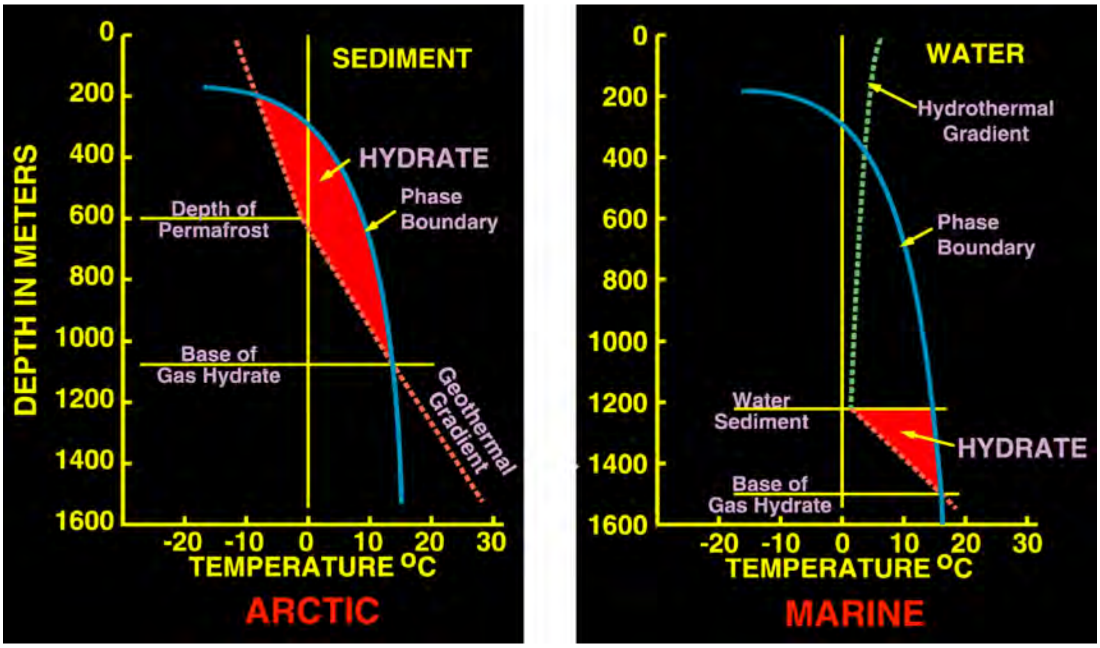

Figure 1.2: Methane Hydrate Phase Diagrams (from Hancock 2008)

Methane hydrates (also known as methane clathrates or natural gas hydrates) are a frozen form of methane gas, bound by water lattices or 'cages' in an ice-like substance as shown in the Figure 1.1 on the previous page.

Methane only exists in hydrate form under specific temperature and pressure conditions, known as the 'gas hydrate stability zone'. The temperature and pressure conditions for hydrate formation differs across onshore and offshore settings. Figure 1.2 illustrates the phase diagrams for methane hydrate formation in arctic and marine settings.

Hydrates are known to occur in a variety of geological conditions, from permeable shales and sandstone to very fine mud deposits.

The occurrence of gas hydrates in continental slope settings is limited to the extent of the gas hydrate stability zone (Figure 1.3) and requires a source of hydrocarbon gas. It has emerged from the body of international research that the particular mode of occurrence of hydrate within this zone is highly heterogeneous. Characterisation of specific sea bed hydrate deposits is a prerequisite to their assessment for potential commercial energy development.

Natural gas hydrates are not uniquely methane, and in their naturally occurring form, can comprise other light gases such as nitrogen, carbon dioxide and ethane. Typically however, a hydrate resource comprises mostly methane, and distinguishes itself in that the concentrations of methane are

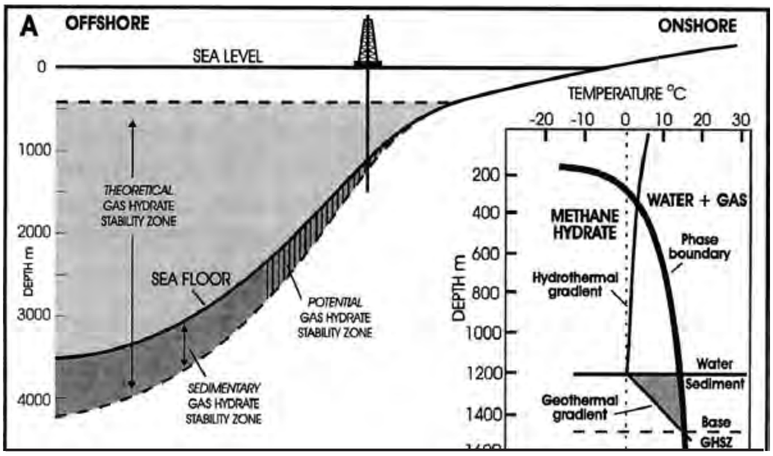

Figure 1.3 illustrates the Oceanic setting for the gas hydrate stability zone and the theoretical, sedimentary, and potential zones of gas hydrate formation. The inset shows arbitrary examples of depth-temperature profiles in which gas hydrates are stable. The phase boundary is for a methane hydrate in pure water (NOAA 2005, adapted from Beauchamp 2004).

Figure 1.3: Oceanic setting for the gas hydrate stability zone

usually greater than 90%. The hydrate state can therefore be considered as a natural purifier when compared with conventional natural gas resources, and this makes hydrates a potentially high quality source of natural gas, with little (if any) downstream processing required to bring it to sales gas quality.

1.3 Energy Potential of Gas Hydrates

Estimates of the energy potential of gas hydrates from around the world have prompted major economies to advance the development of discovered gas hydrate resources. While these estimates of total global resource potential are uncertain at best the World Energy Council's 2007 Survey of Energy Resources (WEC 2007) predicts between 20,000 and 25,000 trillion cubic metres (Tm^3) of hydrates present offshore[2](or 706,293-882,866 tcf). By contrast, the WEC estimate for conventional natural gas reserves, which at 380 Tm^3 (13,449 tcf) is equivalent to 130 years of present global natural gas consumption, pales in comparison.

New Zealand has one of the largest single gas hydrate provinces in the world. Gas hydrates occur along the East Coast (Hikurangi) and Fiordland margins in water depths greater than about 600m. The East Coast province is ideally positioned for energy production because of the size of the resource, a number of identified but unproven hydrate 'sweet spots' and its close proximity to land.

New Zealand's average annual energy consumption from natural gas is of the order of 190 PJ (MED 2008[3]). This equates to approximately 5.1 billion cubic metres (Bm^3) or 0.18 tcf gas. GNS Science's current estimate of the extent of the hydrate resource contained in the Hikurangi Margin area is around 813 - 840 trillion cubic feet (tcf) of natural gas-equivalent, 21 tcf of which is identified as being in 'sweet spots' or areas of potentially commercially viable development (Pecher & Henrys 2003). If fully developed, this quantity of hydrate could supply New Zealand's current energy requirements for natural gas for at least 100 years.

There are many uses that could be envisaged for such a natural gas stream, including export as LNG or as a reconstituted hydrate, conversion to chemicals or fuels, or for power generation and direct use within the domestic market. This study does not consider these alternatives in any detail but instead focuses on the requirements for development under different scenarios, encompassing both export and domestic use options.

1.4 Recovery And Production of Hydrates

The process for exploiting hydrates is little different from that conventionally carried out for the recovery of any hydrocarbon resource.

Extracting methane gas from the solid hydrate phase is the distinguishing element of the process when compared to conventional gas recovery. Whereas in other processes the methane is either free gas trapped below a solid geological formation, or absorbed to coal in the case of coal bed methane, the methane in hydrates is bound by the formation of a cage of water molecules around the methane molecule. Extraction techniques exploit the natural instability of hydrates at lower pressure or higher temperature.

Following a series of short term depressurisation experiments in 2002 at the Mallik site in the Canadian Arctic, a 5 day production trial conducted in 2008 utilising thermal stimulation (ie. circulation of warm water) was sufficient to cause the methane to come away from the hydrate, and confirm predictions from the 2002 programme that gas production from hydrates at the Millik site by means of thermally induced dissociation was technically feasible (Moridis et al. 2008). We note, however, that the Mallik trial was a research project and not an industry-style production test.

More advanced techniques to accelerate methane recovery are being developed and further production testing has been proposed in a number of programmes, but in essence, the major technical constraint to the commercial recovery of hydrate will be well performance and bottom-

2 World Energy Council 2007. Survey of Energy Resources; http://www.worldenergy.org/publications/survey_of_energy_resources_2007/default.asp. Retrieved 20th January 2009

3 New Zealand Ministry for Economic Development. 2008. Gas Use. http://www.med.govt.New Zealand/templates/MultipageDocumentTOC_21222.aspx. Retrieved 20th January 2009

hole stability within the production zone. (Gary Humphreys, pers. comm.) Hancock's presentation to the 2008 New Zealand Petroleum Conference suggests that in comparison to conventional gas reservoir production, a gas hydrate well can be expected to have significantly lower production rates and high water cuts. This in turn will require a larger number of production wells than required in conventional gas field development and likely higher operating costs.

Once the methane has been extracted it can be further transported and processed using conventional natural gas technologies. These technologies are well developed with New Zealand having more than 40 years of production experience based on the Taranaki oil and gas industry.

Figure 1.4 provides a high level illustration of the three commonly accepted methods for extracting gas from hydrate deposits (Ruppel 2007).

1.5 Gas Hydrate Developments: A Coal Bed Methane Analogy

Internationally, methane hydrates as a potential energy resource have generated considerable interest. Seismic and geological surveys of suspected hydrate-bearing regions have demonstrated its wide extent, with deposits confirmed onshore under Russian and North American permafrost and offshore of every continent. In nearly all cases, hydrate development activities have involved commercial, governmental and academic bodies collaborating towards common goals.

In assessing the potential of natural gas hydrates as a future energy resource, the emergence of Coal Bed Methane (CBM) as a commercial energy opportunity is a useful analogy. CBM is the gas found in coal deposits and a cubic metre of coal can contain as much as six or seven times the volume of natural gas that exists in the same volume of a conventional petroleum reservoir.

The U.S.A. has been the world leader in CBM production. It is estimated to have in-place CBM resources of around 700 trillion cubic feet (tcf), of which 100 tcf may be economically recoverable. Due to recent high gas prices and production incentives offered by the US government, and in response to dwindling conventional gas supplies, CBM has shifted from being a scientific curiosity 20 years ago (and simply regarded as a potential hazard to conventional mining) to now accounting for over 1.76 tcf (1860 PJ) annually or almost 10 percent of US natural gas production.

Figure 1.5 tracks the increase in production over the 15-year period from 1989 through to 2004. During this period, production increased some 16 fold with proven reserves now more than 19.6 tcf (20,800 PJ).

Elsewhere, CBM is produced in at least 13 countries, with Queensland in Australia emerging as a major new international player. Several major projects have been recently announced, fuelled by increasing worldwide energy prices, as well as the potential for project financing derived from emissions credits. In 2007, total production in Australia was 103 PJ, up more

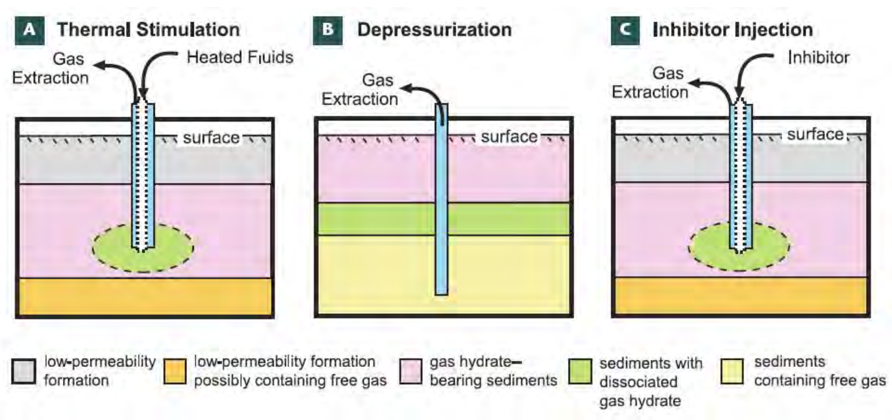

Figure 1.4: Production methods for extracting natural gas from methane hydrate deposits (Ruppel 2007:198)

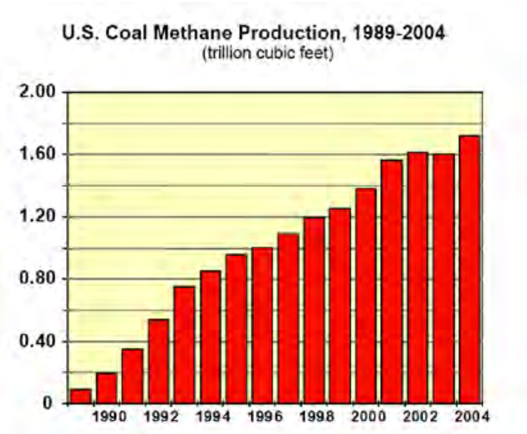

Figure 1.5: US CBM Production 1998-2004 (Pierce 2008; slide 5)

than 40 percent from the previous year, and the rate of growth has not slowed since. The total proven and probable reserves booked by companies in Australia are estimated at close to 7000 PJ[4].

Of current Australian production, more than half is contracted for use in power generation. In addition, there have been a number of LNG projects announced based upon CBM. These include:

- Arrow Energy, who announced plans for a 2.6 million tonne per annum LNG project at Gladstone, commencing production in 2011;
- A 3-4 million tonne per annum LNG project, also based at Gladstone and starting production in 2014, using 170-220 PJ per annum of CBM from Santos;
- Sunshine Gas, who announced plans for a half million tonne per annum project to commence production in 2012; and,
- A proposed gas project by QGC in alliance with BG, for a 3-4 million tonne per annum project to begin production in 2013.

Success with these proposed LNG projects could lead to a quantum leap in CBM production. Total current LNG proposals add up to 500-600 PJ of gas per annum, similar to Australia's total current east coast gas demand. Current indicated reserves are of the order of 15,000-30,000 PJ for the industry as a whole in the long term, around two to four times current booked reserves, and providing a significant boost to Australia's strategic energy reserves.

4 Graeme Bethune, Chief Executive Officer, EnergyQuest; in the February 2008 issue of Petroleum

In summary, CBM has become an increasingly important contributor to world gas supply within 15 -20 years of the first tentative exploration and commercial development of the resource. Fifteen years ago, its potential was largely unknown and untapped. Nowadays, it is no longer seen as a non-conventional resource but as a major new value stream for resource owners.

Recent research and development, technological advances, increasing international interest and rising natural gas prices all suggest that commercial production of gas hydrates may well occur within a similar time frame. Worldwide time frames are being re-evaluated and research efforts becoming more focused on the testing of alternative production strategies that could accelerate time frames.

It is within this context and the expanded geologic and engineering understanding of gas hydrates that Crown Minerals commissioned CAENZ to undertake the work reported here.

1.6 International Engagement

An important lesson from this study is that New Zealand has an exciting hydrates story to tell that is beginning to attract international interest.

This international interest has been built on an extensive platform of international linkages established by New Zealand researchers, and GNS Science in particular, since 2005 with:

- Rick Coffin, Naval Research Laboratorie (NRL);
- Steve Masutani, University of Hawaii;
- Jens Greinert, Gent University, Belgium;
- Ben Clennell, CSIRO;
- Joerg Bialias, IFM GEOMAR;

In the 2008-2009 period, CAENZ, in association with and support from GNS Science and MED, hosted a number of Visiting Fellows from the hydrates field. In addition to public presentations and seminars, these Fellows also provided private briefings to key government officials during their visit. They included:

- Mr Steve Hancock, Well Completion Engineer from APA Engineering, Calgary in Alberta, Canada in March 2008;
- Ms Brenda Pierce, Energy Programmes Coordinator, US Geological Survey in Washington DC, USA in March 2008;
- Dr Karen Kozielski from CSIRO, Melbourne in Christchurch in August 2008;
- Professor Carolyn Koh, Director of the Gas Hydrates Research Centre at the Colorado School of Mines in Wellington and Christchurch in September 2008; and,
- Mr Gary Humphreys, Senior Manager Scientific Drilling and Gas Hydrates from Fugro GeoConsulting, Houston in February 2009;

Other leading figures in hydrates research are also expected to visit New Zealand in 2009, including:

- Dr Judith Schicks, Lead scientist for the GFZ German Research Centre for Gas Hydrates Research (also to sign an MoU with GNS);
- Nina Kukowski, GFZ German Research Centre for Gas Hydrates Research;
- Katrin Schwalenberg, BGR;
- Gesa Netzeband, IFM GEOMAR;
- Sung-Rock Lee, Korean GHDO (also to sign an MoU with GNS);

In addition to the research collaborations that GNS Science and NIWA have been able to leverage with some of the strongest international hydrates research groups, CAENZ has also been actively exploring complementary initiatives with potential strategic and commercial partners to promote and support the development of the New Zealand gas hydrates resource endowment.

The critical importance of an ongoing and expanded New Zealand contribution to international research efforts, in particular to assess the commercial feasibility of gas hydrates, cannot be emphasised enough. Participation in these programmes will ensure that New Zealand will be better positioned to take advantage of international developments and assist in levering the country's limited research funding and investment capacity to ensure the optimal realisation of the economic potential of this strategic resource.

It is also likely that there will be visitors to other New Zealand research institutions, such as NIWA and Otago University, during this period with the potential to contribute to the New Zealand gas hydrates effort. It is important that linkages at the appropriate levels be established with them during their visit.

1.7 Study Context

In developing this study, we recognise that there are international groups prepared to assist New Zealand to develop its gas hydrates resource endowment. This has been evident since around 2005, with interest expressed by the US Naval Research Labs and the University of Hawaii for the establishment of a Gas Hydrates Research Corridor offshore of east coast of the North Island of New Zealand[5]. More recently, expressions of interest in, and support for, research collaborations have been received by both members of the study team and researchers from GNS and NIWA (e.g. GNS Science's collaboration with IFM-Geomar for the 2011 return of the survey vessel, RV Sonne).

In addition to factors such as the presence of potential gas hydrate 'sweet spots' in close proximity to land on the East Coast of the lower North Island, the willingness of international researchers to participate in a New Zealand hydrates initiative has largely also been driven by the strong and close linkages that researchers in New Zealand at GNS, NIWA and the University of Otago have been able

5 Ingo Pecher, GNS Science. Personal communication ca. 2006

to leverage. As will be come clearer in later sections of this Report, an expansion of these linkages is a necessary component of any national strategy to advance New Zealand gas hydrates.

We also intend to demonstrate that the successful development of the gas hydrates opportunity will require expertise and skills that go beyond science through to commercial interests, to ultimately produce an engineered solution specific to New Zealand's unique circumstances and national interests.

Finally, this report sets out to draw together the various strands of thinking and learning from current international activities, including the economic and technical considerations that should drive future decision making, into a comprehensive assessment of the opportunity for a potential gas hydrates development opportunity in New Zealand.

Examination of this study, focused on a prospective gas hydrates site on the lower East Coast of the North Island, provides a business case for further investigation and for investment into science and engineering studies.

Chapter 2 that follows provides the context for the study in more detail.

2 STUDY CONTEXT

2.1 Introduction

CAENZ has maintained a "Frontier Resources and Oceans" programme since 1996, with the objective of ensuring that potential maritime and energy resource opportunities are not sterilised through inappropriate policy settings or inadequate national planning. A list of the Centre's publications and activities in this area may be found in the References and Selected Bibliography sections of this report.

A primary driver for the Centre's programme has been its view that despite New Zealand being an energy-rich country, the necessary critical investments in further delineation of this country's energy resources and expansion of its energy reserves capacity has not occurred at a level required to maintain this country's long-held strategic advantage of a secure and relatively inexpensive energy supply. Instead, the various studies undertaken by the Centre suggest that the New Zealand energy sector is at risk of entering a period of transition and uncertainty which, unless action is taken now, could well manifest itself in uncertain supply, higher costs and an increasing exposure to the vagaries of the global oil market.

Figure 2.1 below sets out the Centre's analysis of the supply capacity of developed fields, fields nearly ready for development and discovered reserves as of 2005. This shows a potential supply gap arising within the next decade unless there is an expansion of the gas reserves inventory. Whilst recent exploration success suggests strongly that the New Zealand natural gas resource has the potential to satisfy local demand (unlike many other countries), future supplies remain tight and reliant on continuing exploration success.

This just-in-time approach presents its own risks for energy consumers; foremost amongst them is the continued reliance by some major users on LNG as a backstop fuel, should gas production levels fall to a point where producers are unable to supply existing or future planned gas fired electricity generation capacity.

In such a scenario, the risks to the New Zealand economy are significant. If nothing is done to secure adequate indigenous primary energy sources, the alternative is imported fuels. As the Maui gas field comes to the end of its productive life, the projected future imbalance between gas demand and gas supply will intensify. It is within this context that gas

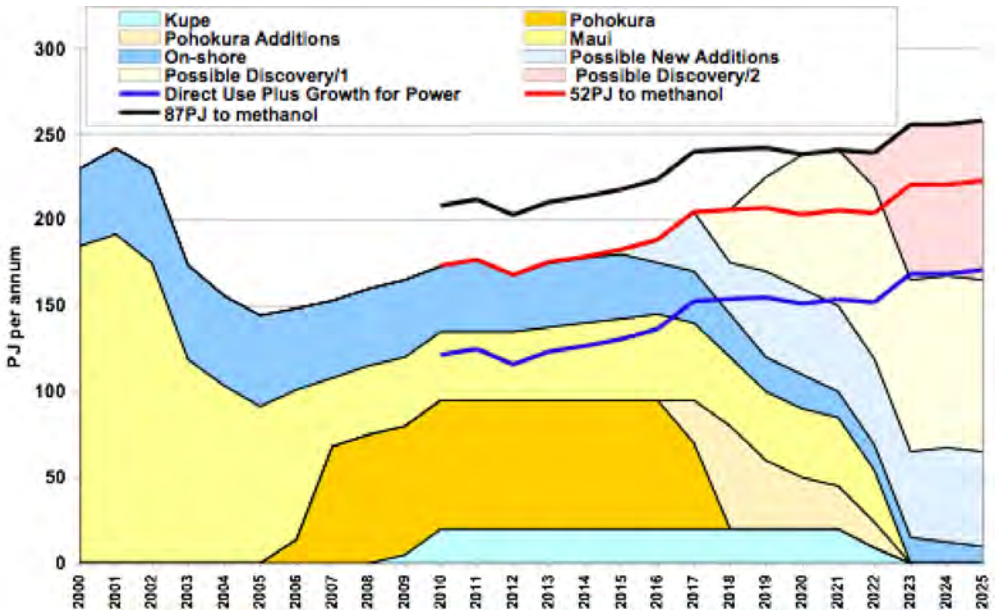

Figure 2.1: New Zealand Natural Gas Supply Capacity (CAE 2005). An Investigation into Thermal Fuels Options and Their Contributions to Energy Security. CAE Comments Volume 04)

hydrate development needs to be considered. New Zealand is richly endowed in gas hydrates and thus offers a potentially relatively low carbon indigenous energy supply.

Following a study in 2006 for the Ministry for the Environment that considered possible government interventions to support the development of New Zealand's maritime resource opportunities (CAENZ 2006), CAENZ has maintained a watching brief on international research and development efforts related to methane hydrate extraction and exploitation. The size of the endowment and its economic potential (both nationally and globally) suggests that hydrates, if proven economically attractive, could transform this country's energy markets. The key distinction between the present era and a likely hydrate scenario will be the scale of the opportunity and the economic transformation that would ensue from expected investment in upstream export-led activity.

Consequently, and at the invitation of Crown Minerals, CAENZ and GNS Science brought together a special session at the 2008 New Zealand Petroleum Conference held in Auckland to look at the current status of hydrate research and development world-wide and the prospective value of New Zealand's inferred gas hydrate resources. An important contribution to the session was the presentation of a road map for commercial development by GNS Science[2]. This road map suggested that marine hydrates represented a significant medium- and long-term opportunity for New Zealand that would most likely occur concurrently with other international efforts.

The success of the conference was followed by a series of briefings to officials in Wellington, which reinforced the lessons of the Conference that there was a high level of interest in methane hydrates internationally, as well as the potential competitive advantages for pioneering a hydrates initiative in New Zealand.

Almost without exception, participants in these discussions argued strongly for a greater level of investment in science, engineering and commercial/strategic relationships to advance the economic potential of the New Zealand hydrates resource. Moreover, it was argued, that a strong New Zealand commitment to hydrates research would likely attract some of the huge international research investment and commercial interest, due to the scale of the New Zealand resource and the proximity of potential research sites close to shore.

However, for such an opportunity to be fully realised, it was considered vital that an understanding of both the context and the options for the economic development of the resource be developed to a level sufficient to identify the preferred development pathway and the optimal structure for ongoing investigation of the opportunity to create the maximum value for New Zealand.

It was recognised that in order to advance the commercial development of these marine resources, New Zealand will need to commit to ongoing, wide-ranging and substantial investments in studies of the subsurface geology, geo-technical and engineering investigations required for hydrate extraction, and the engineering technical appraisals of the required recovery and production facilities. To this end, the objectives of this study are as outlined below.

2.2 Study Objective

This study broadly expands on the New Zealand Gas Hydrates Road Map[3], produced by GNS Science and presented at the 2008 New Zealand Petroleum Conference. It aims to assess the options for commercial development of marine hydrates in New Zealand and establish the economic feasibility for doing so based on review of the international experience and the motivation behind the extensive international programmes currently under way world wide. Beyond this, the study also examines the opportunity to extend current New Zealand hydrate research as a provider of exploration, appraisal, and development solutions expertise through new collaborations with current international players.

New Zealand scientists have made a number of important recent advances in the last

2 Beggs, M. et al (2008). New Zealand Gas Hydrates Road map (GNS Science Report 2008/06)

3 Beggs, M. et al (2008). ibid.

few years and international linkages with leaders in gas hydrate research. The strategic benefits of closer R&D relationships are amply demonstrated by current initiatives such as the 2011 German IFM-GEOMAR research programme for the Hikurangi Margin that GNS Science have successfully been able to attract to New Zealand, and the positive reception to the CAENZ-GNS bid to host the 2011 International Conference on Gas Hydrates in New Zealand. Although New Zealand came in as a close second in this highly contested bid, GNS Science has however successfully bid to host 'Fiery Ice', the 7th international Methane Hydrates R&D workshop, in Wellington in 2010.

In addition to the above, the Options Analysis also sought to:

- provide an objective, independent and 'over-the-horizon' perspective on the potential economic benefits of the New Zealand of commercial exploitation of its marine hydrate resources;
- identify and illustrate the options and potential development pathways for New Zealand to more effectively leverage its limited resources to build expertise and capacity to commercialise the resource opportunity;
- identify and implement a series of targeted, multi-stakeholder initiatives that would provide New Zealand with the research, commercial and strategic capacity to engage with international hydrates research efforts;
- facilitate participation by New Zealand research institutes in international hydrates research efforts and collaborations, as well as the participation of New Zealand industry players in international commercial consortia.

Ultimately, it was hoped that this study would build our understanding of the options for the economic development of the resource so that New Zealand might be better placed to capitalise on the commercial opportunity when the opportunity presents itself. Whilst, inevitably, commercial exploitation of the resource will be reliant on international investment and technical expertise for the development of the opportunity, it is the view of the study team that there are no compelling reasons why New Zealand could not lead the world in this field as it did in the pioneering commercialisation of the Maui gas field in the early 1970's.

To do so, however, will require that a platform for an integrated network approach industry, government and the research sector be created that would allow for the optimal realisation of the economic potential of the hydrates resource endowment for the benefit of New Zealand at the right time.

Whilst the study recognises the importance of this necessity, to deliver on such an imperative will require a degree of lateral thinking "outside the box", combined with an appropriate set of considerations and an enabling policy framework that recognises the unique characteristics of 'frontier' resource opportunities. The Canadians have used such a model, the Mallik 2002 and 2007 internationally partnered production well programmes, to develop their methane hydrates knowledge base. Their experience has been used to inform this study.

The study also recognises that New Zealand participation in international research collaborations is a prerequisite for keeping in step with technological developments in this field and for leveraging the establishment of a strong domestic research and industry capability in gas hydrates. The magnitude of the inferred resource potentially available for recovery presents for New Zealand a significant transformational opportunity of major importance to this country.

In this respect, GNS Science and NIWA, as New Zealand's key science organisations, will need to play a critical role in advancing the country's capacity to capitalise on this endowment. GNS Science leads New Zealand's core research program focused on gas hydrates as an energy resource, funded by FRST in 1993 and is leading a Marsden project on gas hydrates and sea floor stability in collaboration with NIWA and Otago University. In addition, GNS Science has on-going related research programmes on the tectonics, geologic framework and petroleum systems of New Zealand gas hydrate provinces, as well as related water chemistry and isotope research and has maintained an active research program focused primarily on gas hydrates as an energy resource for the last

5 years. NIWA too has focused on the tectonic structure and geological framework of the margins, and recently on oceanography and ecosystems around gas hydrate sites. We note that both research institutes have essentially bootstrapped their capabilities in the face of relatively limited funding. However, we suggest that the research objectives of the international collaborations may not have been aligned necessarily with the commercial imperatives of the New Zealand E&P sector.

In undertaking this work, it has also become apparent that access to world class marine services companies (based in Taranaki but operating throughout the world), in addition to access to world class scientists within GNS Science, NIWA and the universities, will contribute to New Zealand's attractiveness as a destination for collaborative international gas hydrates research initiatives. Operating conditions that are climatically more favourable and sheltered than the Arctic, and in potentially shallower water than India or the Nankai Trough, provide an additional rationale for New Zealand to aspire to become a world leader in the area of marine hydrate development.

2.3 Study Approach

The key limiting factors to commercial production of the hydrate deposits will be establishing the basis for site selection, resource characterisation and determining technology capability. These are the primary factors that will drive the economics of the commercial development, rather than any current appraisal of the geology or environmental settings. This is due to the structure of gas hydrate reservoirs, which requires a larger number of wells and more sophisticated equipment (and hence a higher CAPEX and OPEX) compared to conventional gas production, while lower production rates will result in a reduced rate of return and the delayed achievement of break even and a positive cash-flow position.

To this end, the study has focused very much on bringing together a development pathway to replicate a likely commercial development scheme to thus provide realistic estimates of the likely economics of production. The development of this case study involved significant interaction with international collaborators, who were not only used to firm up the technical bases behind the analysis but also provided a platform for discussion on the strategic options available to New Zealand for promoting the hydrates opportunity. The outcome of these discussions was development of a project plan and business case for a well resourced and coordinated development effort, leading to a possible future investment decision. This is encapsulated in the notional gas hydrate development pathway presented in Chapter 7 of this report.

A strong project team was established whose skills comprehensively encompassed the commercial, technical, science and research. Their profiles are provided in Appendix 1.

The preliminary results were presented to MED in a workshop prior to completion of the report and subsequent contributions from the peer review process have been incorporated into this Final Report.

3 NZ HYDRATE RESOURCES

3.1 Summary of Hikurangi and Fiordland Provinces

3.1.1 Status of Knowledge

Until recently, the occurrence of crosscutting seismic reflectors in seismic reflection lines has been the main tool for establishing the presence of hydrate on a regional scale in most geologic settings. Theoretical models (e.g. Xu & Ruppel 1999) suggest that free gas at the Base Gas Hydrate Stability Zone (BGHS), generating Bottom Stimulating Reflectors (BSRs), is a pre-requisite for gas hydrate deposits at higher concentrations.

However, this has yet to be fully established; and in isolation, appears to be a very limited approach, as hydrate has been shown to occur far more widely than the occurrence of BSRs (Johnson 2006), and in a diverse variety of habits (with a vast range of "quality" characteristics) that are not readily discriminated without additional independent data (as hydrate saturation and the exact position of deposits are not directly related to the location of BSRs). Irrespective of these anomalies, in the absence of more sophisticated data, BSRs remain the best indicator of hydrate deposits in New Zealand waters.

On parts of the Hikurangi margin, the grid of seismic lines to map BSRs is still relatively coarse, with lines typically tens of kilometres to >100 km apart from each other. Other countries, such as Canada, India, Korea, China, Taiwan, and of course Japan, have mandated denser grids of seismic lines, often only several km apart, as a first step in gas hydrate reconnaissance. The seismic data available for the Hikurangi margin includes oil and gas exploration industry lines, which are archived by Crown Minerals, and data from research cruises by GNS Science, NIWA (and predecessor DSIR) and their international collaborators. These data include a range from shallow penetration, low fold multi channel seismic data, to deep penetration, high fold industry standard exploration data. Substantially more data is required, and seismic surveys do not need to be specifically designed for gas hydrate discovery. Whilst several excellent candidate sites have already been discovered for more in-depth appraisal and resource characterisation initiatives, new data will almost certainly reveal many other high profile targets.

Other geophysical methods are proving useful to complement reflection seismic surveying. In particular, joint seismic and controlled-source electromagnetic (CSEM) surveys appear promising for quantifying local gas hydrate deposits. Sea floor resistivity measured by CSEM allows determination of the concentration of free gas or gas hydrate but cannot readily distinguish between either type or pore fill. Seismic parameters on the other hand are strongly affected by the presence of free gas but less so and differently by gas hydrate; hence, the combination of both techniques is a powerful tool to discover and quantify gas hydrate deposits.

A CSEM survey over an offshore Wairarapa deposit (Figure 3.5) has recently been used to propose a conceptual model at a gross scale to constrain gas hydrate saturation (Schwalenberg et al. 2008; Schwalenberg et al., submitted-a). Preliminary results indicate maximum hydrate saturation of over 50%, making this site a prime candidate for more detailed characterization.

Evaluation of combined seismic and CSEM data is currently being conducted in another offshore Wairarapa region, the Porangahau Ridge (Figure 3.7). Initial results have led to the detection of shallow gas hydrate deposits and their relation to fluid-flow conduits (Toulmin et al., 2008).

3.1.2 History of Gas Hydrate Exploration in New Zealand

New Zealand's Exclusive Economic Zone (EEZ) contains two known gas hydrate provinces (Townend, 1997): the Hikurangi continental margin east of the North Island (Katz, 1981; Henrys et al., 2003; Pecher & Henrys, 2003) and the Fiordland continental margin southwest of the South Island (Fohrmann et al., in press).

Hikurangi Margin

The first BSR surveys of Hikurangi were reported by Katz (1981). BSRs were later noted in the SOP Lee seismic section documented by Davey et al. (1986) and Lewis and Pettinga (1993).

Seismic data acquired on the NZ-French GeodyNZ Survey, using the research vessel L'Atalante in 1993, led to the first BSR maps and heat flow analysis of the Hikurangi Margin (Townend, 1997; Henrys et al., 2003), and provided the basis for the first FRST funded gas hydrates project at GNS Science.

Using data collected by a number of fishing vessels and NIWA surveys, Lewis and Marshall (1996) reported discoveries of numerous cold temperature, methane-rich fluid vent sites and associated sea floor ecological communities.

The North Island Geophysical Transect (NIGHT) Project in 2001 detected BSRs and the flattening of the "Rock Garden" site, an area of sea floor erosion and methane venting.

Seismic sea trials by the research vessel N.B. Palmer in 2003 raised the hypothesis that sea floor erosion may be linked to gas hydrate freeze-thaw cycles at the top of the gas hydrate stability zone, which was later discussed in Pecher at al (2005).

'Faure seeps', a methane anomaly in a water column on the southern edge of the Rock Garden site was discovered during a 1 day programme of bathymetry and water chemistry using a towed METS sensor by the NIWA research vessel Tangaroa in 2004. More information on the Faure seeps may be found in Faure et al (2006).

In 2005, GNS acquired the first industry standard seismic line to analyse potential gas hydrate sweet spots on the Porangahau Ridge using the Pacific Titan (Voyage 05CM-038).

The first dedicated gas hydrates cruise was Voyage TAN0607, using the NIWA research vessel Tangaroa in 2006. During this cruise, the first gas hydrate samples were collected (Voyage TAN0616). This was a collaborative programme, and involved researchers from NIWA, GNS and the US Naval Research Lab.

A major recent advance occurred in 2007, when the German research vessel Sonne, undertook 3 survey legs over a 2.5-month period dedicated to gas hydrates and vent sites on the Hikurangi Margin. These voyages focused on six specific sights, referred to informally as Wairarapa, Uruti Ridge, Porangahau Ridge, Omakere Ridge, Rock Garden and Builders Pencil (Figure 3.1) as well as advancing knowledge of the regional tectonic framework. A number of papers based on the data from this voyage will be published in a special volume of Marine Geology sometime in 2009.

Fiordland Margin

BSRs have been recognised from seismic data from the Fiordland Margin for more than 20 years (e.g. Townend 1997). However, whilst there has been substantial research on the

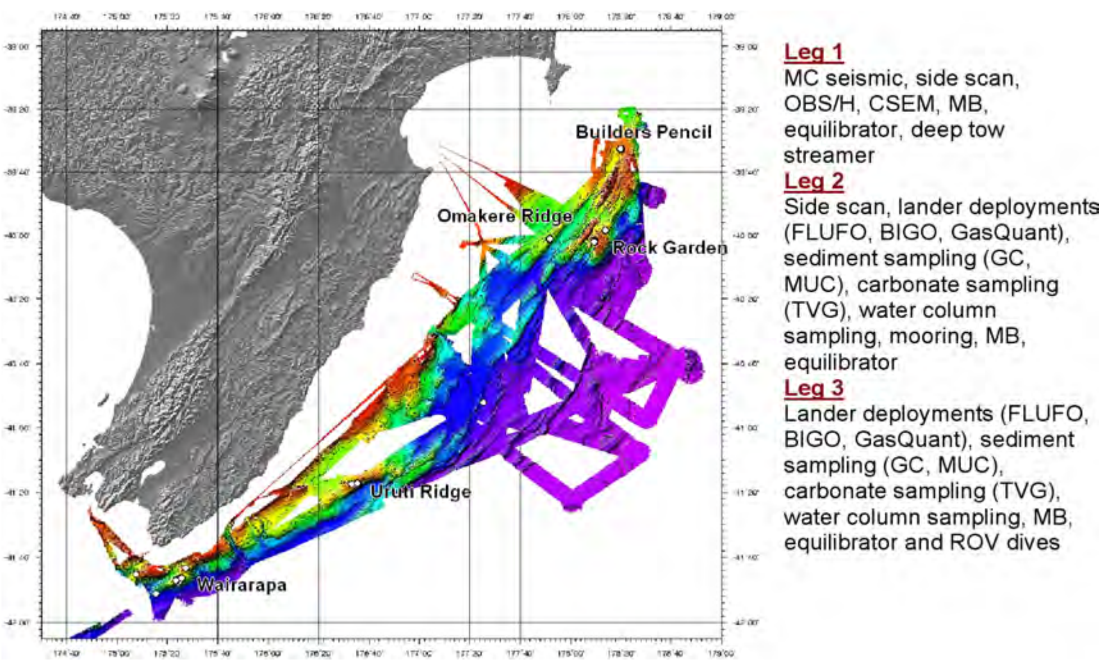

Figure 3.1: RV Sonne Voyage SO191, Hikurangi Margin, 2007 (Greinert 2008 presentation to EGU)

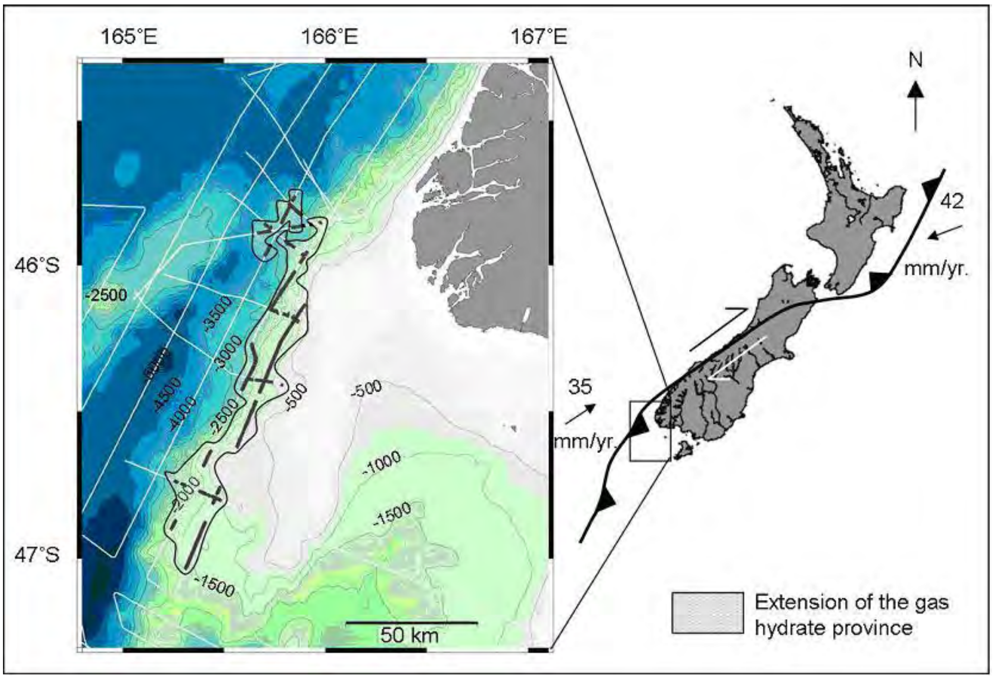

Figure 3.2: Map of Fiordland Margin (from Gorman, Fohrman & Pecher 2006)

tectonic structure of this margin (e.g., Lamarche and Lebrun, 2000; Lebrun et al., 2000; Barnes et al., 2002; in press), knowledge of hydrate accumulations in the northern Puysegur region is limited by the sparse dataset available, a scarcity of sediment samples and well data (Gorman 2008) and an absence of supporting information on sea floor geology. Figure 3.2 illustrates the geological relationship between the Hikurangi and Fiordland gas hydrate provinces.

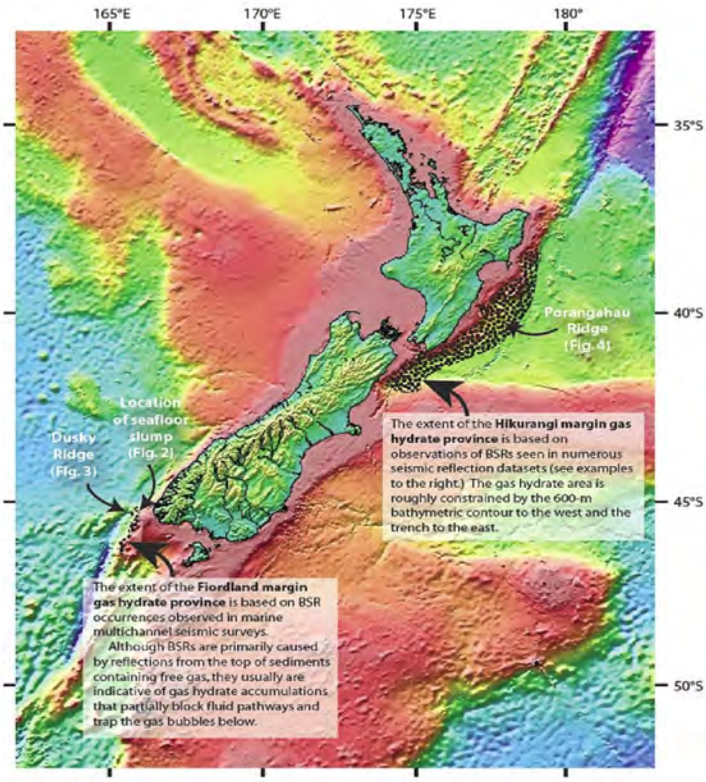

Figure 3.3: Hikurangi & Fiordland Margin Gas Hydrate Provinces (Gorman 2008)

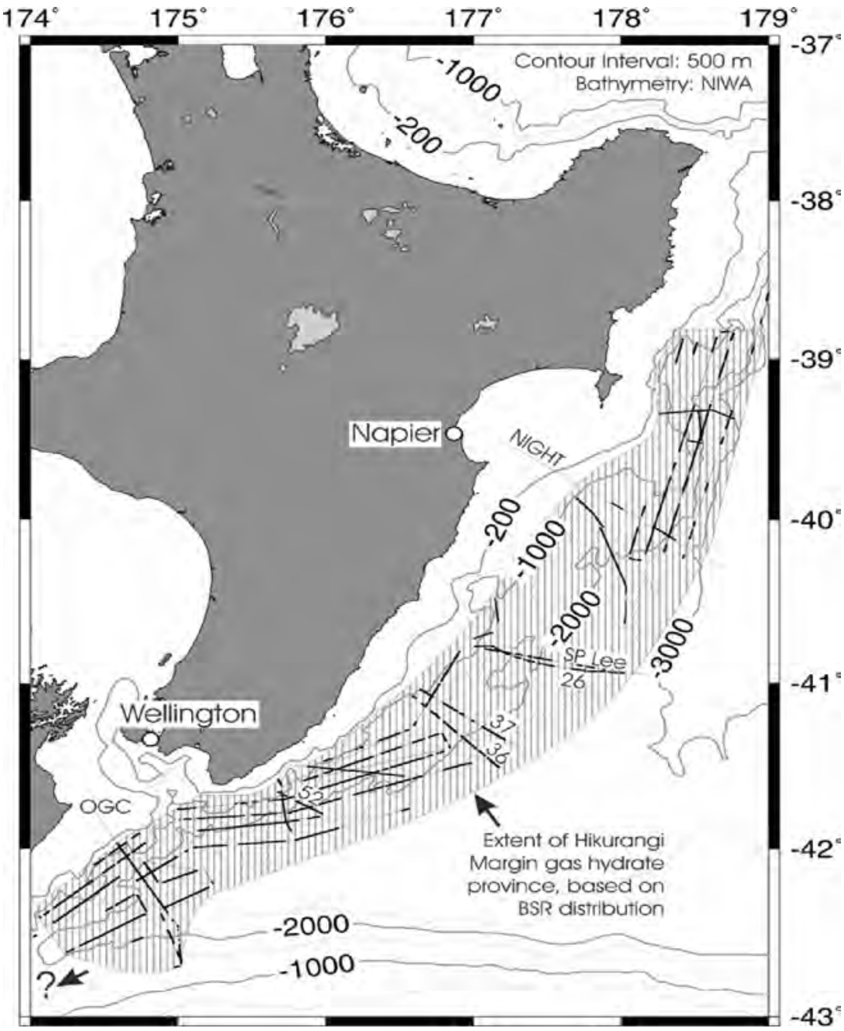

Figure 3.4: Hikurangi Margin Gas Hydrate Province (Gorman, Fohrman & Pecher 2006: p18)

Hydrate accumulations in the Fiordland Margin region appear to be associated with slope failure, with one particular landslide (in Figure 3.3) corresponding to where the BSR appears to outcrop on the sea floor (Gorman 2008; Crutchley et al 2007).

New Zealand Gas Hydrate Production Characteristics

Both provinces, the Hikurangi and the Fiordland Margins, are situated above plate-boundary subduction zones. Subduction zones are very active geologically, leading to high rates of fluid flow, which is known to be a controlling mechanism for gas for hydrate formation (Ruppel & Kinoshita 2000). The strong geological heterogeneity associated with subduction zones also favours formation of areas with highly concentrated gas hydrates, sometimes referred to as "sweet spots" (Pecher & Henrys 2003). For the economic evaluation of gas hydrate production and subsequent commercial production, the detection of such "sweet spots" is an obvious priority.

The Hikurangi Margin (illustrated in Figure 3.4), at approximately 50,000 km^2 in size (Pecher & Henrys 2003), covers a larger area than the 2200 km^2 Fiordland province (Fohrmann et al., in press). A comparison of the two gas hydrate provinces are provided in Table 3.1.

On available data, the Hikurangi Margin also shows more indications of "sweet spots" than the Fiordland gas hydrate province (Pecher & Henrys 2003), which provides one of the keys reasons for the focus of this report on the Hikurangi province. Such "sweet spots", defined by seismic reflection coefficients, occur where the BSR has a relatively strong amplitude (Henrys et al., in press). The precise

	Hikurangi Margin	**Fiordland Margin** [*Note 1*]
Area of gas hydrate	50,000 km^2 [*Note 2*]	2,200 km^2
Recoverable gas at STP per hydrate volume	n/a	114.58 tcf (3.24 Tm^3)
Volume of gas hydrate	228.5 km^3 [*Note 3*]	10 km^3
Volume of gas at STP	37,474 km^3 [*Note 3*]	1,600 km^3 / 40 tcf (1.13 Tm^3) [*Note 4*]
Volume of recoverable gas at STP	23,010 km^3 / 813 tcf (23 Tm^3) [*Note 3*]	1100 km^3

Table 3.1: Comparison of the Potential Production Capacity of the Hikurangi & Fiordland Gas Hydrates Provinces.

Note 1: adapted from Gorman, Fohrman & Pecher (2006) p27.

Note 2: adapted from Henrys, Pecher & CHARM NZ Working Group.

Note 3: from Henrys et al (2008) p11 and Pecher & Henrys (2003)

Note 4: from Henrys et al (2008) p12)

significance of the amplitude sweet spots with respect to hydrate resources remains unclear. A map of these sweet spot locations is provided in Figure 3.5.

It is worth noting however, that gas hydrate saturation for the Fiordland province have been inferred from seismic data to be quite high (~20-30% of pore space at ~40% porosity) over large areas (Fohrmann et al., submitted) compared to the Hikurangi margin. Despite the absence of ground-truthing from drilling, this proposition may be realistic and has received support from evidence from recent drilling in the South China Sea[1]. It is therefore possible that other gas hydrate provinces may also be present elsewhere in New Zealand's EEZ. Gorman et al (2008) have suggested that gas hydrates may also be present in the Deepwater Taranaki, Canterbury and Great South Basins (Figure 3.6).

1 Zhang et al. 2007. Successful and Surprising Results from China's First Gas Hydrates Drilling Programme. Fire In The Ice, 2007, Fall Edition

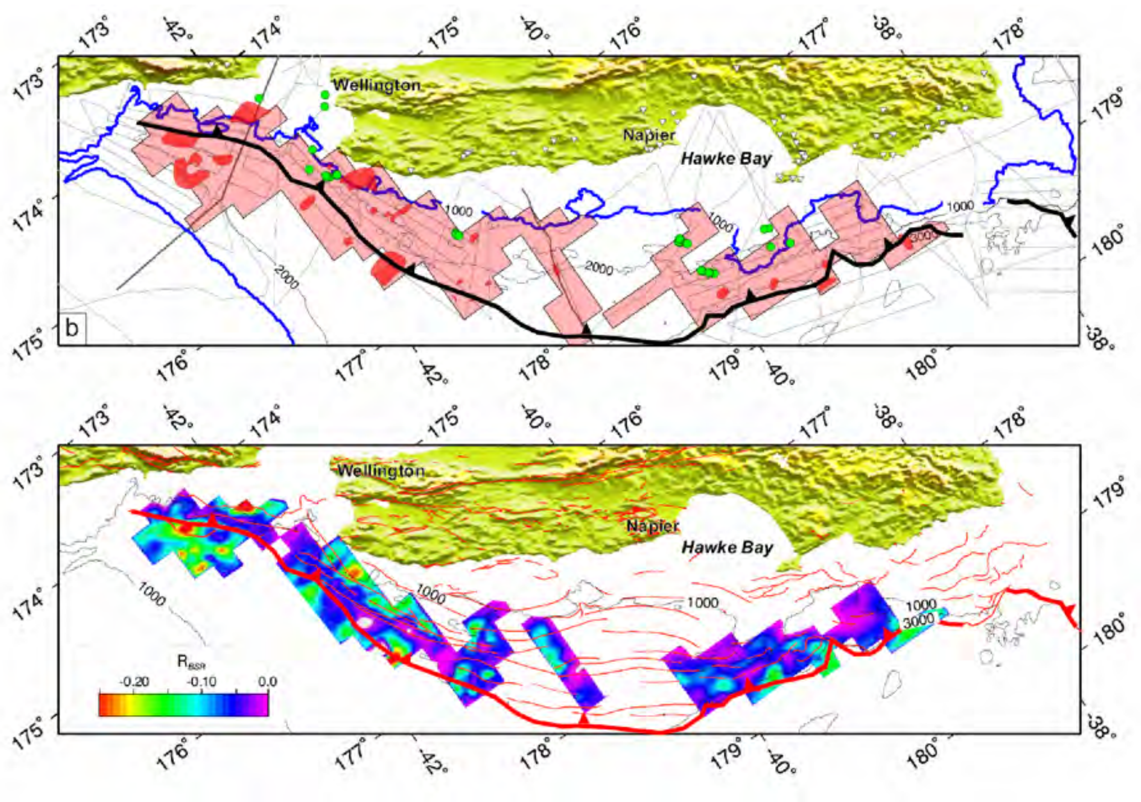

Figure 3.5: Hikurangi Margin Gas Hydrate 'Sweet Spots' (Pecher 2006: p18)

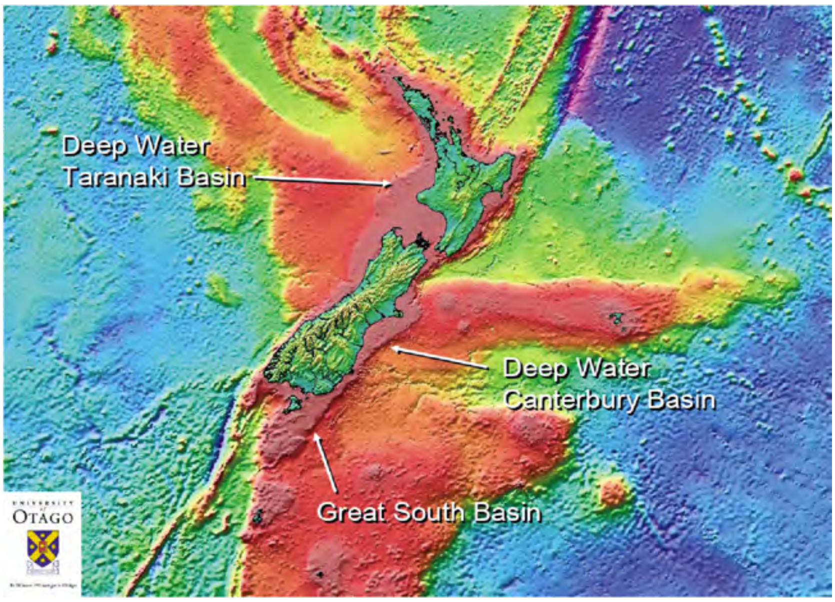

Figure 3.6: Other NZ Gas Hydrate Provinces (adapted from Gorman, Fohrman & Pecher: p36)

In addition to the relatively higher distribution of sweet spots, the accessibility and proximity of the Hikurangi margin to the major population centres of the North Island (e.g. Wellington and Napier), strongly argue for the Hikurangi Margin gas hydrate province to be the focal point for the economic evaluation of commercial gas hydrate production in New Zealand (Beggs et al., 2008).

Beyond the quantity and concentration of the resource, another key factor for production is the quality of the reservoir rock, in particular permeability (i.e. the ease at which gas moves

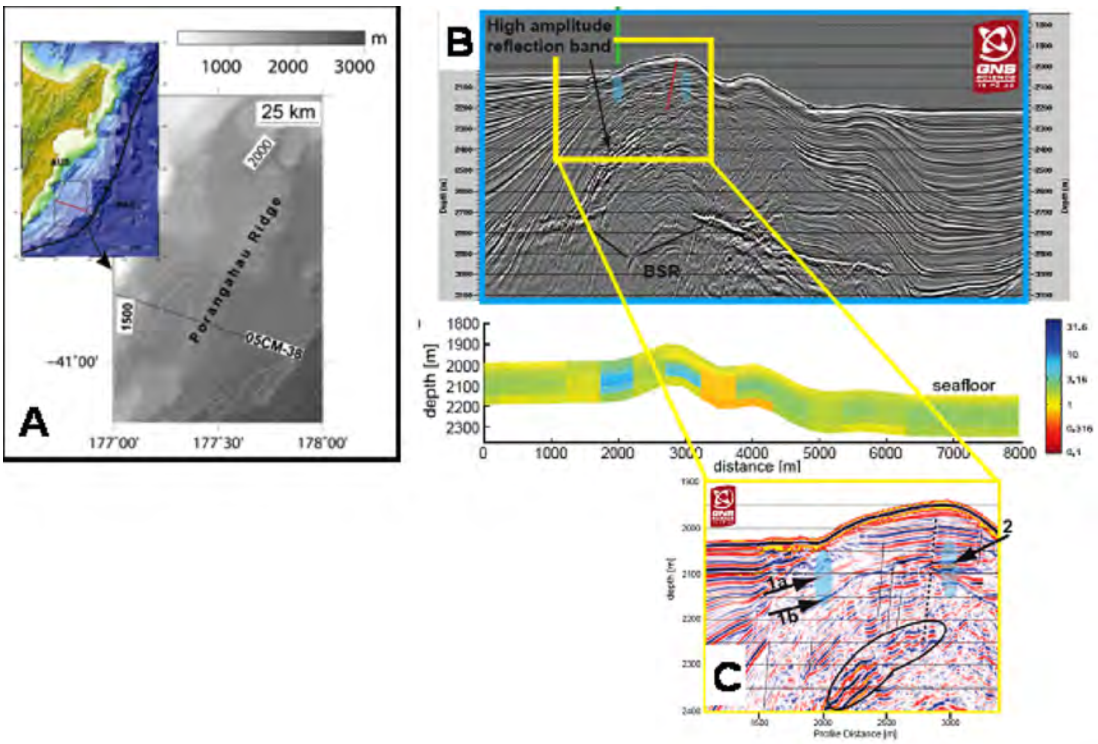

Figure 3.7: Shallow gas hydrates from joint analysis of seismic and CSEM data on the Porangahau Ridge. (A) Location map, (B) resistivity profile (after Schwalenberg et al. (submitted-b)) beneath seismic profile, (C) detailed locations of resistivity anomalies (blue ellipses) and identification of seismic reflections possibly associated with gas hydrates (after Toulmin et al. (2008)).

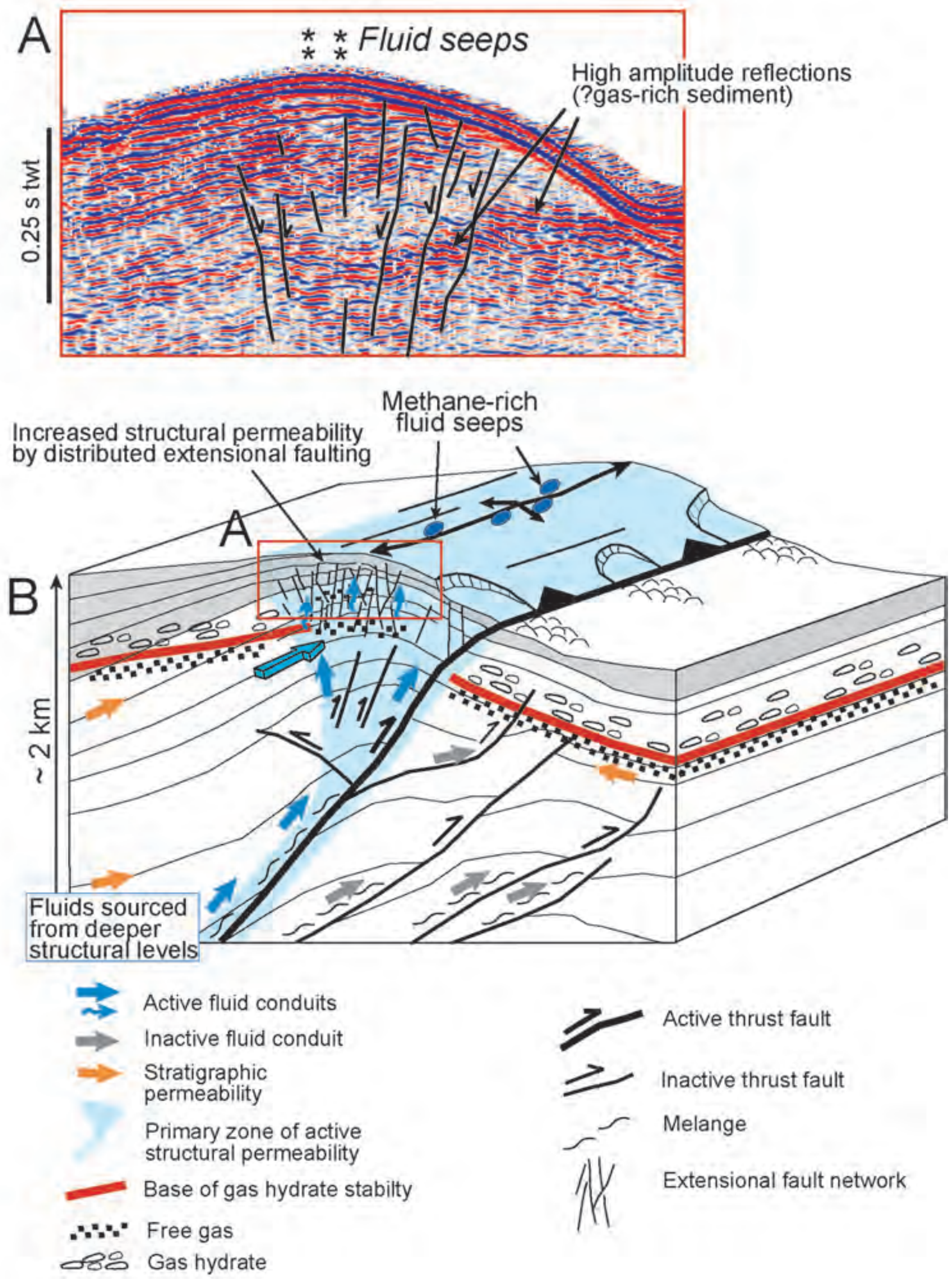

Figure 3.8: from Barnes et al. (In press). Summary of tectonic, stratigraphic, and hydrogeological aspects of the Hikurangi Margin imbricate thrust wedge. Cross section of the offshore margin 35 km south of Rock Garden, at ~2X vertical exaggeration.

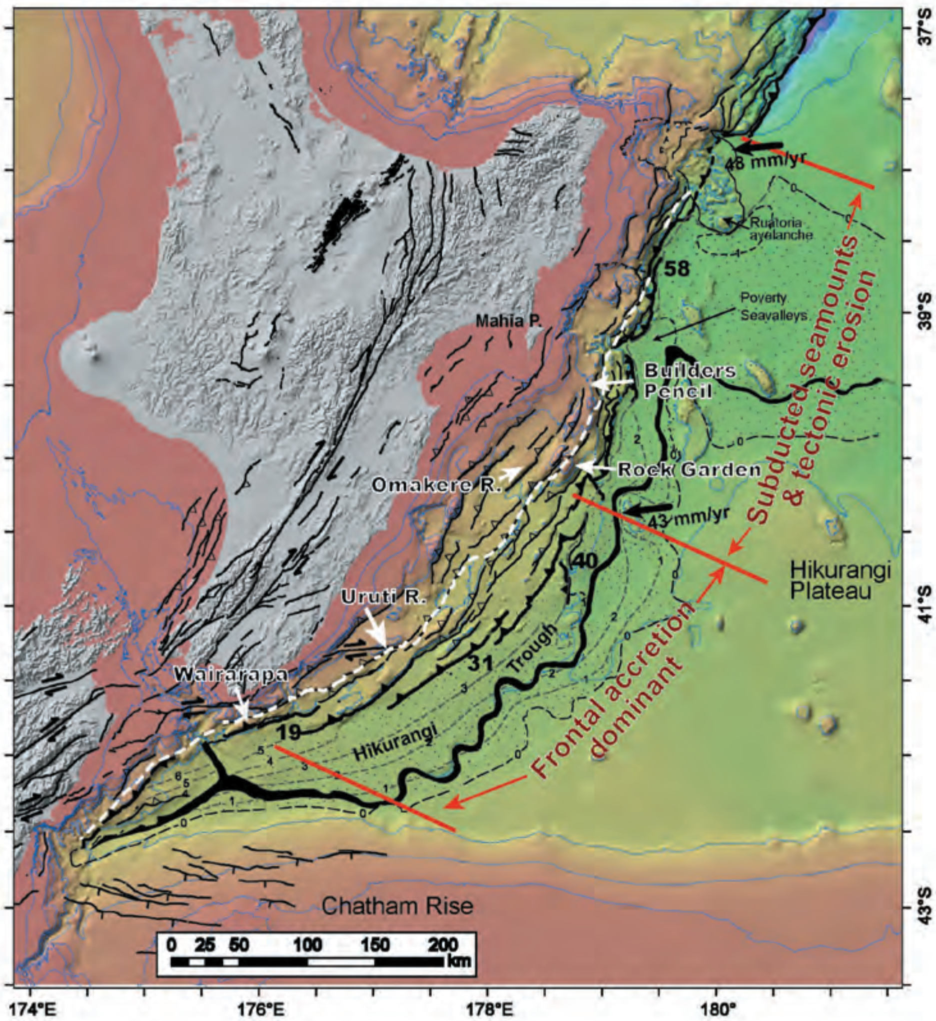

Figure 3.9: Overview of the Hikurangi subduction zone, showing morphology and major active faults. Bold thrust is the principal deformation front. The bold black line in the Hikurangi Trough is the meandering Hikurangi Channel. LR, Lachlan Ridge; RR, Ritchie Ridge. (Barnes et al., in press)

through sediments to the bore hole). Samples from the sea floor further north along the Hikurangi Margin shown in Figure 3.8 suggest that some of the hydrate deposits may be hosted by fractured mud stones (Pecher et al., 2008). Barnes et al. (in press) suggested the shallow seismic stratigraphy of different seep areas appears to vary greatly, but has not been accurately dated at the specific seep sites (Figure 3.7). Consideration of regional seismic reflection characteristics and sparse sea floor samples led them to infer that the Wairarapa and Omakere Ridge seeps are located on late Pleistocene slope sediments. At Uruti Ridge they are developed on probable Pliocene strata which are exposed at the crest and seaward flank of the ridge. The Builders Pencil substrate appears to be Miocene and/or Pliocene strata, which overlie older rocks exposed on the seaward flank of Ritchie Ridge. The Rock Garden seeps, located on the western side of Rock Garden, may lie on a substrate of exposed Cretaceous and Paleogene rocks, or on an eroded cover sequence of Miocene-Pliocene age. The sediment types and strong heterogeneity associated with this convergent margin make it likely however, that significant gas hydrate reservoirs are sand-hosted deposits, the highest-quality host rock and similar to the gas hydrate fields targeted on the Nankai Trough offshore of Japan.

The source of gas is another key factor in reservoir characterisation. The gas composition of sampled seeps onshore along New Zealand's east coast is predominantly methane (Giggenbach et al., 1993) and analysis of their carbon and hydrogen stable isotopic signature supports a thermogenic origin, i.e., similar to conventional gas fields. Studies of onshore oil seeps suggest that hydrocarbons of the East Coast were derived from Late Cretaceous-Paleocene marine source rocks (Rogers et al., 1999). It is therefore possible that methane for hydrate formation offshore is also, at least partially, of thermogenic origin, similar to conventional gas fields. However, all but two offshore samples from shallow piston cores (Faure et al., submitted) point to biogenic processes for methane formation, i.e. by bacterial action on sedimentary organic matter in the first few hundreds meters beneath the sea floor.

3.1.4 Geological Framework

Evaluating a gas hydrate resource is more than an estimation of the quantity of methane and how much energy it can produce. It is also about understanding the origin of the resource, the mechanisms of its formation and the factors that control its spatial distribution and temporal stability.

Over the last 25 years, both GNS Science and NIWA have focused their efforts on the structure and geomorphology of the Hikurangi subduction margin, and have acquired an in-depth knowledge of regional structural complexity and variation along strike in response to changes in subducting crustal structure, convergence rate and obliquity, and sediment supply (Figure 3.8). A number of seismic reflection and multi beam bathymetric voyages have provided the underpinning data used to interpret the stratigraphy of the subducting sequence, the upper plate tectonic structures, and the geological framework for cold vent seep sites.

There is a clear relationship between the seep sites and major thrust faults, which are conduits for fluid and gas migration sourced from the deeper, inner parts of the thrust wedge, and probably from subducting sediments. Fluid and seep sites typically lie in about 700-1200 m water depth on the crests of thrust faulted ridges along the mid-slope. Beneath the sea floor seeps on ridge crests there is typically a conspicuous break in the BSRs, which are widespread along the length of the margin, and commonly a seismically-resolvable fault-fracture network through which fluids and gas percolate (Figure 3.8). The Cretaceous and Paleogene inner foundation are considered, on the whole, relatively impermeable and this focuses fluid migration preferentially to its outer edge via major low angle thrust faults and the décollement.

3.1.5 Sea Floor Ecology

In addition to a number of research voyages exploring geophysical and geological aspects of the Hikurangi & Fiordland subduction zones, to date there have been two research voyages with the specific aim of studying assemblages of cold seep fauna in New Zealand waters. A number of relevant papers on cold seep fauna are listed in Appendix 2.

These voyages have been undertaken by benthic ecologists to evaluate the resources and the environmental impact of exploitation. The voyages have demonstrated that seepage is widespread on the Hikurangi Margin in depths of 800-1200 m and that the great majority of sites where water column gas flares are present are colonised by populations of obligate chemosynthetic fauna, often in high abundances. Knowledge of these fauna is at a very early stage but already it is clear that some species, and even genera, are new to science and there is evidence that these sites may represent a completely new bio-geographic province of chemosynthetic fauna. It is also likely that some species are extremely long-lived (Lamellibrachia sp. >150 y) and that populations at some sites have persisted for a very long time. Given the dependence of these organisms on active seepage at the sea bed, their potential importance in terms of global biodiversity, and our incomplete knowledge of their ecology, it will be important to evaluate fully the potential effects on them of large scale gas hydrate extraction at an early stage of the planning process. There is evidence that some seep sites have already been impacted by deepwater fishing activities but the effects of gas hydrate extraction on a commercial scale are potentially greater.

Only one research voyage has been directly relevant to marine microbial ecology, and permitted the investigation of microbial diversity and their links to gas hydrates. This voyage only evaluated the microbes for their potential to degrade the methane in the water column and sediments, but did not investigate the in-situ microbial populations for their potential to produce methane. Currently, there is limited understanding of the capability of the in-situ microbial populations to produce methane and how this may add to the total methane pool. Further research is required

Reservoir	Nationality	Continental / Offshore	Distance from shore	Depth	Reservoir geology	Estimated size
Hikurangi Margin Province[1]	NZ	Offshore	20km (Wairarapa site)	600-2800m water + 460m seabed		813 tcf (23 Tm³)
Canada (total)[2]						1,550-28,600 tcf (43.9-809 Tm³)
Mallik	Canada	Continental	N/A	1150m		3.5 tcf (0.1 Tm³)
Beaufort / McKenzie Delta[3]	Canada	N/A	N/A	N/A	N/A	311 tcf (8.8 Tm³)
USA (total)[4]						318,000 tcf (9,000 Tm³)
Alaskan North Slope[5]	USA	Continental	N/A	N/A	N/A	590 tcf (16.7 Tm³)
Alaskan North Slope / Prudhoe Bay	USA	Continental	N/A	N/A	N/A	85-450 tcf (2.4-12.7 Tm³)
Gulf of Mexico Province[6]	USA	Offshore	200km+	800-3000m water, visible on sea floor	Sand	21,444 tcf (607 Tm³)
Gulf of Mexico Province	USA	Offshore	200km+	800-3000m water, visible on sea floor	Sand	11,088 -34,396 tcf (314-974 Tm³)
Blake Ridge[7]	USA	Offshore	200-300km	2000-4800m water +190-450m seabed	Mud	1,000-1,300 tcf (28-37 Tm³)
Japan (total)[8]						1,765 tcf (50 Tm³)
Nankai Trough	Japan	Offshore	48km	2000m water +200m seabed	Mud	565-953 tcf (16-27 Tm³)
Nankai Trough[9]	Japan	Offshore	30mi from Honshu Island	500m water	N/A	39 tcf (1.1 Tm³)
Ulleung Basin/Sea of Japan[10]	Japan/South Korea	Offshore	150km (Japan) 200km (Korea)	1800-2100m water +150m seabed	Sand	600MT
Krishna-Godavari Basin	India	Offshore	200km	1300m water	Sand & mud	66,800 tcf (1,891.6 Tm³)
Mahanadi Basin	India	Offshore	30-40km	500-1000m water	N/A	
Andaman Islands	India	Offshore	N/A	850-2000m water	N/A	
Konkan Basin	India	Offshore	N/A	N/A	N/A	

Table 3.2: Spatial and physical characteristics of key gas hydrates research sites

Table References:

1 *Pecher & Henrys 2003*

2 *Majorowicz & Osadetz 2001 in Osadetz et al 2005*

3 *Osadetz & Chen 2005 in Osadetz et al 2005*

4 *Collett 1995 in Osadetz et al 2005*

5 *Collett 1997 in Osadetz et al 2005*

6 *Frye et al 2008 in Fire & Ice Spring 2008: p1*

7 *DoE 1998a*

8 *MITI/JOGMEC 1988 in Osadetz et al 2005*

9 *NGVGlobal, "USA and Japan Agree to Joint Methane Hydrate Study", 23 May 2008. http://www.ngvglobal.com/en/technology/usa-and-japan-agree-to-joint-methane-hydrate-study-01891.html*

10 *http://www.platts.com/Natural%20Gas/Resources/News%20Features/asiapacificlng/korea.xml*

to assess the contribution of the marine microbes to both the methane production and degradation at these sites.

3.2 Comparison with Selected Marine Gas Hydrate Provinces

Figure 3.10 illustrates gas hydrate occurrences around the world. The following section presents an overview of the five offshore gas hydrate provinces that have been drilled as part of national gas hydrate initiatives in recent years: the Nankai Trough offshore Japan, the Gulf of Mexico, several basins around India, the South China Sea and the Ulleung Basin offshore Korea.

Table 3.2 provides a comparison of the spatial and physical characteristics of some of the key target sites for current gas hydrate research activity.

3.2.1 Nankai Trough, Japan

The extent of the Nankai Trough Gas Hydrate Province, the focus region for Japan's future offshore gas hydrate exploitation (MH21 2002), is provided in Figure 3.11. Two exploration drilling campaigns have been conducted revealing significant gas hydrate deposits with

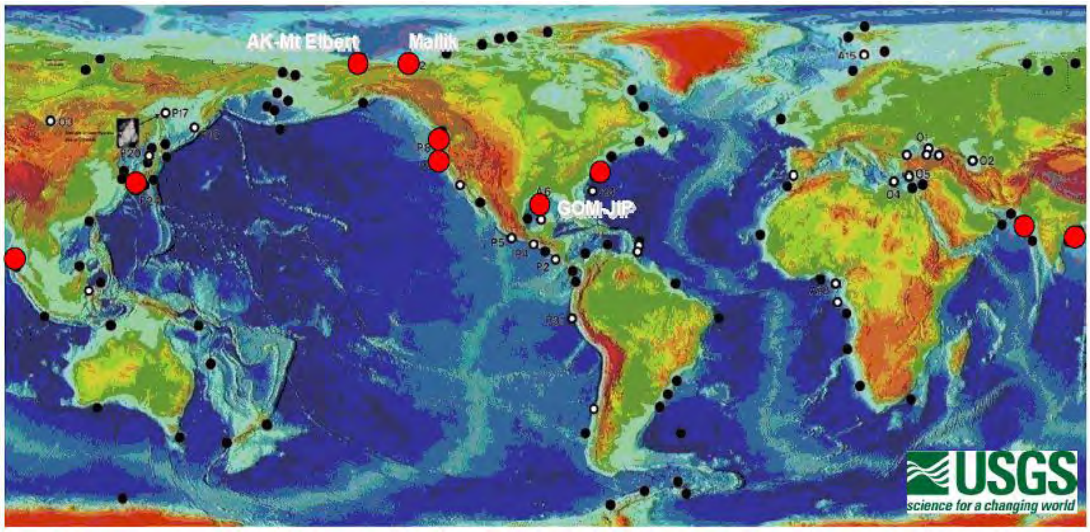

Figure 3.10: Worldwide occurrences of hydrates (USGS)

saturation often over 80% of pore space in sand-dominated turbidites (Takahashi et al. 2001), the most promising type of reservoir (Boswell & Collett 2006).

Significant advances have been made in the development of reservoir characterization techniques that can be readily employed elsewhere, such as the interpretation of seismic attenuation and the use of vertical seismic profiles (A. Sakai, pers. comm., 2006, summarised by Pecher et al. (submitted)). It is clear that the Japanese MH21 gas hydrates consortium is currently the world leader in gas hydrate exploitation, having commissioned both the onshore drilling campaigns through Canadian Arctic hydrates (the Mallik site, which recently concluded a short run but highly successful production test; i.e. Kurihara et al. 2008), and the offshore Nankai campaigns. New Zealand could benefit immensely from the Japanese findings due to the geological similarity between the Hikurangi Margin and the Nankai Trough.

2 US Geological Survey; from http://walrus.wr.usgs.govt/globalhydrate/

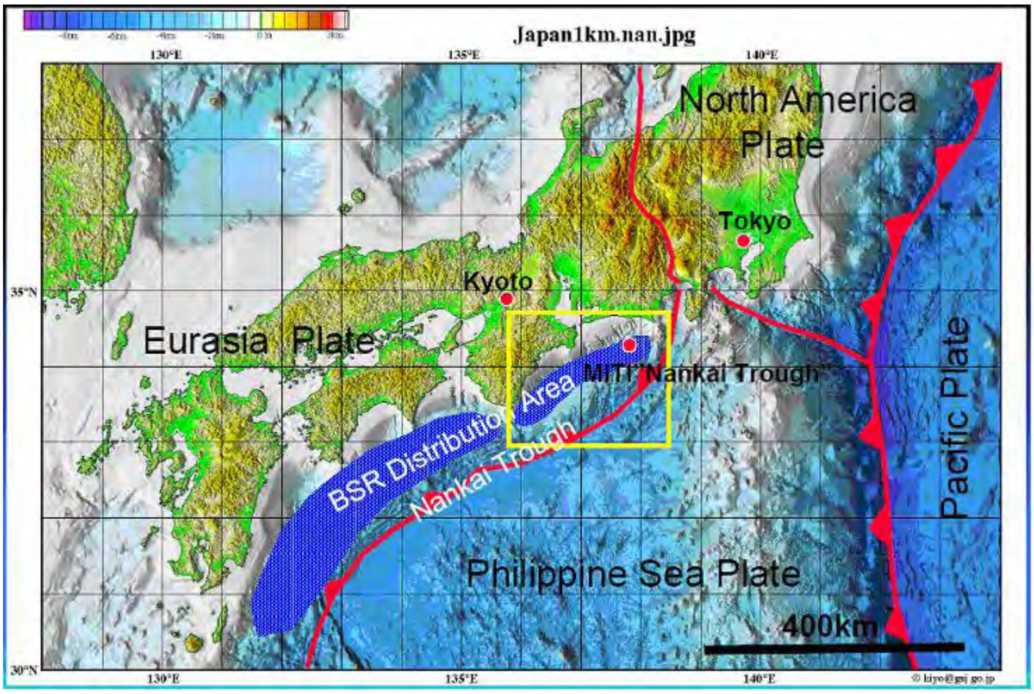

Figure 3.11: Nankai Trough Gas Hydrate Province (USGS)[2]

3.2.2 Gulf of Mexico

Gas hydrates in the Gulf of Mexico (GoM) are being investigated as part of a Joint Industry Program (JIP) brokered by the U.S. Department of Energy (DoE 2008; Chevron 2009) and led by Chevron. A map indicating the extent of gas hydrate indications in the Gulf is provided in Figure 3.12; while an indication of sites that were drilled in 2005 and scheduled to be drilled in April-May 2009 is provided in Figure 3.13.

The initial target of the GoM JIP was gas hydrate production to increase the life-span of installations above conventional gas fields (M. Max, pers. comm., 2008 via I. Pecher) – an approach adopted successfully for shallow-gas pockets. Figure 3.14 illustrates the correspondence of gas hydrate and oil and gas occurrences.

Geologically, the GoM is quite different from New Zealand in that it is dominated by gravity tectonics, including geologically rapid upward movement of sub-surface salt diapers with associated faulting providing migration pathways for gas and fluids from deep hydrocarbon reservoirs (Ruppel et al. 2005). Faulting and salt also causes distortion of fluid and heat flow, significantly affecting gas hydrate stability (Taylor et al. 2000; Ruppel et al. 2005). Locally, high salinity also reduces gas hydrate stability (Wright et al. 1999). These effects are thought to lead to a strongly distorted base gas hydrate stability zone (BGHS), and the general lack of bottom simulating reflections (BSRs) and continuous reflections from free gas trapped at the BGHS. Nevertheless, large gas hydrate deposits have been found near the sea floor as a result of exploration and development drilling into deeper oil and gas reservoirs.

3.2.3 India

The Indian government commissioned an extensive drilling programme along the east and west coast of India in 2006 (Collett et al. 2006) using the best-equipped drilling vessel for gas hydrates exploration, the D/V JOIDES Resolution.

This programme took advantage of the existing availability of densely spaced seismic reconnaissance lines, which resulted in the discovery of several significant gas hydrate fields, in particular, the Krishna Godavari (KG) Basin and a gas hydrate system situated offshore of the Andaman Islands, as illustrated in Figure 3.15.

While some hydrate fields were detected in sand-dominated layers (although the offshore Andaman Islands site revealed gas-hydrate-bearing volcanic ash layers), much of the hydrate was present in fractured mud stones – this mode of occurrence seems to set the KG Basin apart from some other passive-margin settings.

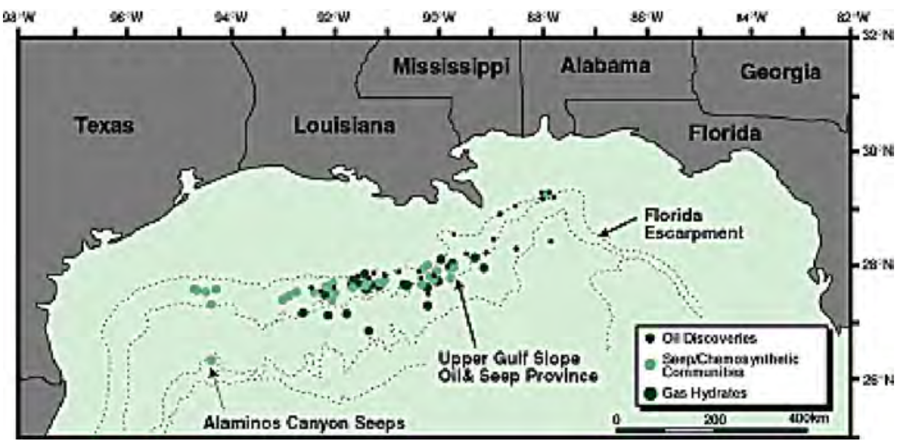

Figure 3.12: Gulf of Mexico Gas Hydrate Province (Quarterdeck Vol 5(3): Dec 1997)

Further studies are planned to test the viability of producing gas from such fractured reservoirs (deemed the second-most desirable reservoir rock for prospectively, (Boswell & Collett, 2006)).

Extensive exploration surveys are also planned in the near future to characterize these gas hydrate deposits, both in fractured reservoirs and in sand lobes (K. Sain, pers. comm., 2009).

The passive-margin setting of India's gas hydrate province is different from New Zealand (except for the Andaman margin). However, experience gained from gas hydrate production from fractured reservoir rocks may be significant for New Zealand because fractured mud stones may be a wide-spread host rock for gas hydrates off New Zealand (Pecher et al., 2008).

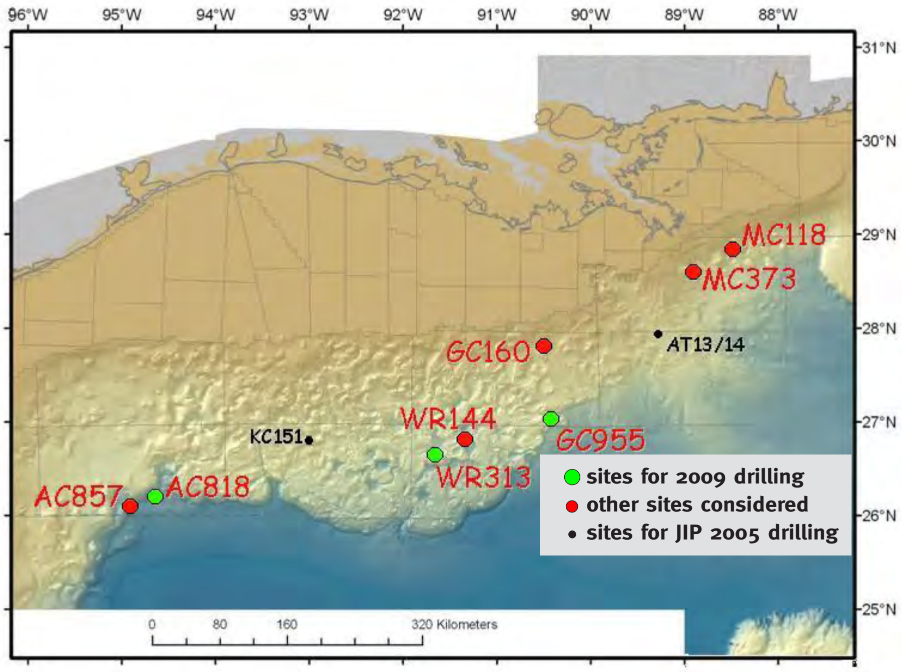

Figure 3.13: Sites of recent and scheduled drilling (April-May 2009) in the Gulf of Mexico Gas Hydrate Province (Rose & Boswell 2008)

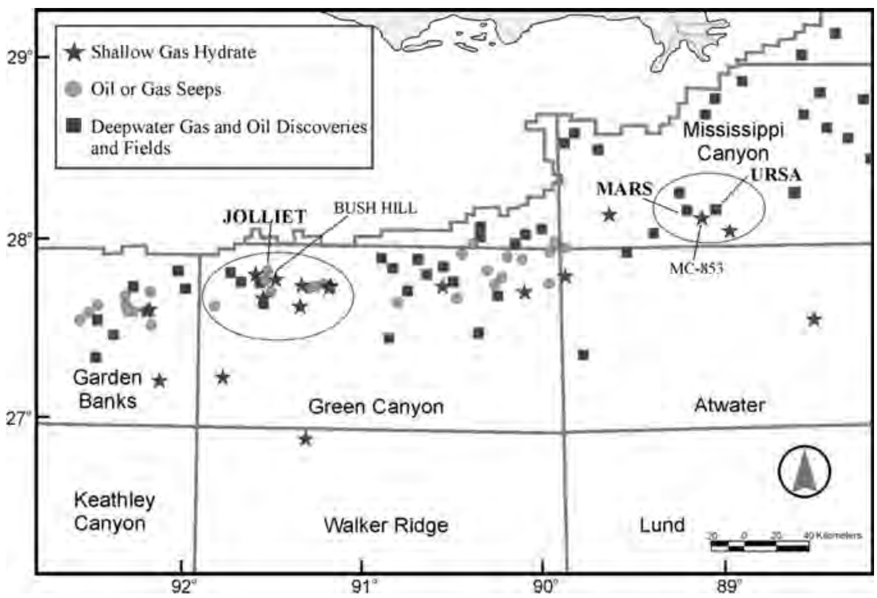

Figure 3.14: Map of Texas A&M gas hydrate drill cores with related oil and gas seeps and fields in the Gulf of Mexico (Sassen et al. 1998)

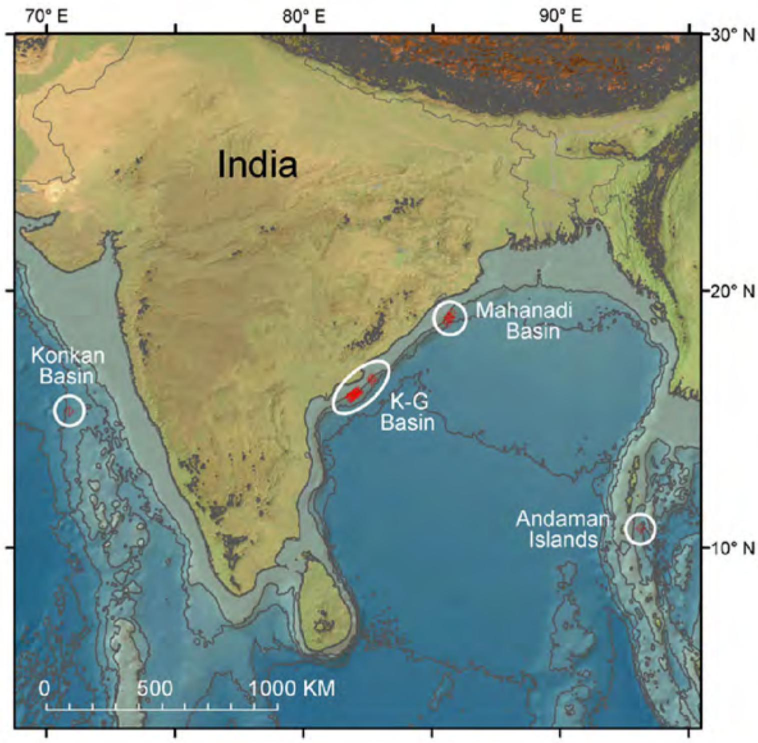

Figure 3.15: India Gas Hydrate Provinces (USGS[3])

3.2.4 China

A major gas hydrates exploration programme was conducted by China in the South China Sea in June of 2007 (Zhang et al. 2007). Figure 3.16 provides the drilling location for this programme.

While the results from this programme are still being compiled, one of the surprising findings was that while gas hydrate distribution was laterally uniform as expected for this passive-margin setting, hydrate saturation reached 20-40% of pore space immediately above the BGHS. These saturation are much higher than on the Blake Ridge for example, where in a similar undisturbed passive-margin setting, hydrate saturation was only a few percent (Holbrook et al., 1996).

3.2.5 Ulleung Basin, South Korea

The South Korean Gas Hydrate National Programme is centred on the Ulleung Basin in the East Sea (figure 3.17). The latest research campaign was successfully completed in November 2007 (Park et al., 2008).

Gas hydrates were encountered both in coarse-grained, sand-dominated sediments and in fractures. Results from investigating gas hydrate systems in fractures (Riedel et al., 2008) may be highly significant for evaluating New Zealand's gas hydrates.

Concluding Remarks

In summary, India, China, and Korea have recently joined the U.S. and Japan in the group of countries with national programs for gas-hydrate drilling. It appears that for geologic reasons, results from the Japanese program are still of most significance to New Zealand. However, New Zealand could gain invaluable information from a number of other programmes.

In the time frame available to us, it was not possible to explore such opportunities in depth. However, it will be an important component of any subsequent work stream.

Chapter 4 that follows reviews the scope of international activities.

3 Retrieved from http://energy.usgs.gov/other/gashydrates/in-diamap.html, 19th February 2009

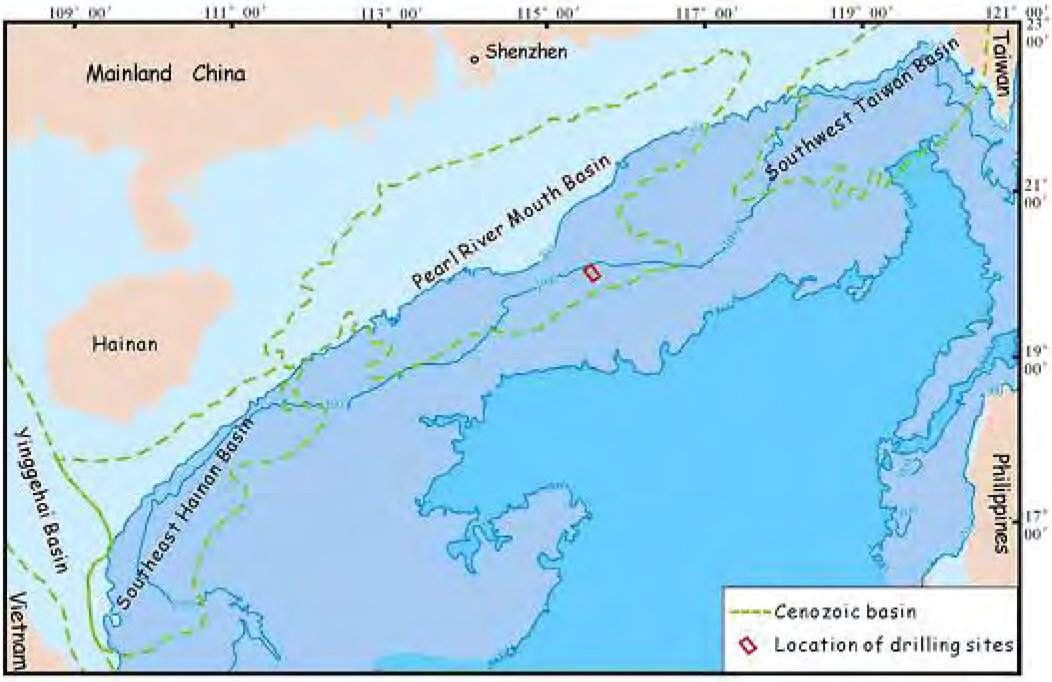

Figure 3.16: China Hydrate Province, South China Sea (from Fire & Ice, 2007 Fall Edition)

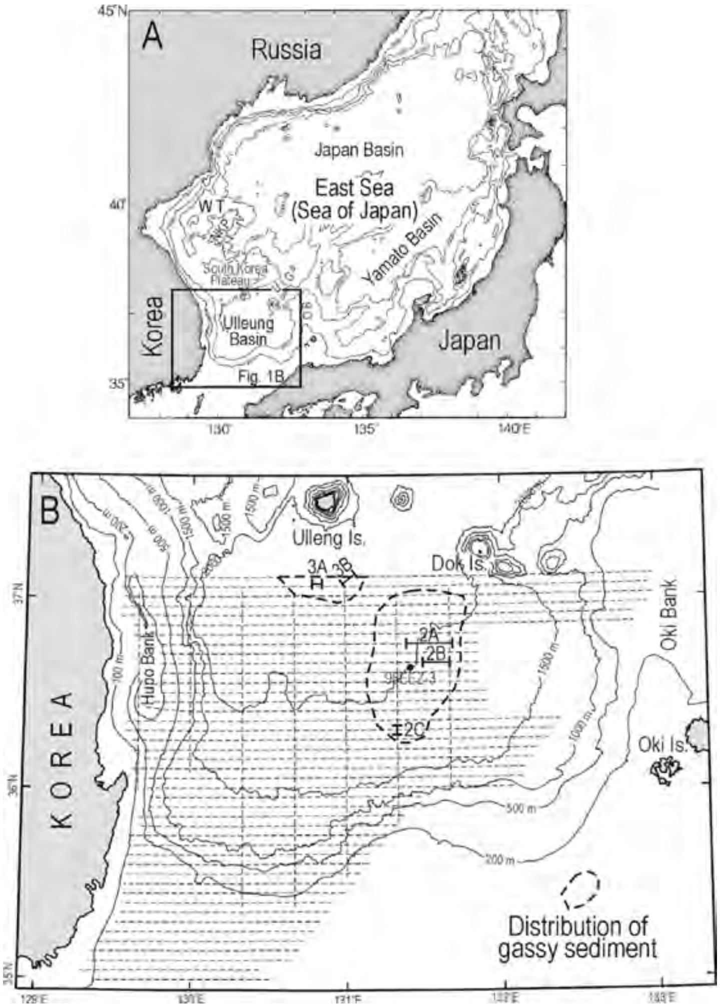

Figure 3.17: South Korea Gas Hydrate Province, Ulleung Basin (Lee & Chough 2003)

4. INTERNATIONAL APPROACHES TO HYDRATE ASSESSMENT AND DEVELOPMENT

Introduction

The discovery of naturally formed hydrates is, in fact, very recent, dating from Makogon who in 1969 first reported the existence of natural gas hydrates beneath the Siberian permafrost. Since then, numerous gas hydrates deposits have been discovered and today, natural gas hydrates are known to exist in subterranean deposits in Siberia and North America and off the shores of all the world's continents (Figure 3.9).

Increasing awareness of gas hydrates as an energy resource has prompted many of the world's leading economies (including the United States, Canada, Japan, Korea and India) to actively engage in hydrate exploration operations in an attempt to quantify their potential energy reserves. For a number of nations whose economies are almost totally reliant on imported fuels, the discovery of gas hydrates within their territorial boundaries represents a significant potential improvement to their future security of supply position. A high level comparison of the five key international hydrates provinces is provided in Table 3.1.

Exploration for gas hydrate deposits relies on conventional hydrocarbon surveying technology, including the use of 2-D and 3-D seismic surveying to produce Bottom-Simulating Reflectors (BSRs), and core samples. Interpretation of this data has led to a general consensus that the global hydrate resource is truly immense, with estimates varying from 10 to 100 times the known conventional natural gas reserves around the world.

The sections that follow summarise the current state of international exploration activity. It must be remembered, however, that the approaches of different countries involved in hydrates assessment are affected by several considerations:

- Existing national energy market structures;
- Demand versus supply as a principal consideration;
- Stage of economic development;

Japan's early leadership reflects its high energy consumption, very limited indigenous supplies, advanced stage of development, and the high level of state involvement in the energy sector.

Although Japan's programme is now run by a state agency-led consortium (MH21 2002), in several of the other relatively developed countries (e.g. India, South Korea), the state oil companies are very much the driving force.

Conversely, in the North American countries, government administrative and scientific agencies are involved in consortia with private enterprise (and in some cases, as in the Mallik project in the Canadian Arctic, with foreign entities).

In all cases, however, Government funding predominates, via granting arrangements and agency budgets, even with private sector participation. The Gulf of Mexico Joint Industry Programme (JIP) is typical of these arrangements, and involves funded participation by Chevron and ConocoPhillips (U.S. Oil companies), U.S. Geological Survey and Minerals Management Service (U.S. federal agencies), Total (French oil company), Schlumberger (logging company), Reliance Industries (Indian oil company), JOGMEC (Japanese agency), and Scripps Oceanographic Institute, Rice University, and Georgia Institute of Technology (U.S. universities).

4.1 GLOBAL EXPLORATION ACTIVITY

4.1.1 United States

The United States has been at the forefront of gas hydrate exploration, with significant onshore finds such as the Alaskan North Slope and offshore discoveries around the Blake Ridge hydrocarbons fields and in the Gulf of Mexico. Current estimated reserves are of the order of 318,000 tcf (Collett 1995) with the Alaska North Slope estimated to contain 590 tcf gas in place (Collett 1997). The current US government budget for hydrates research is US$165 million per year over five years from 2005 (Osadetz et al., 2005).

The Alaskan North Slope project is now a base of operations of leading research into gas hydrate resource development, led by the US Department of Energy (US DoE) and BP Exploration Alaska Inc. (BPXA) Research operations in Alaska and in the Gulf of Mexico aim to characterize the local gas hydrates resource; and in the case of Gulf of Mexico, to investigate the sea floor stability issues associated with gas hydrates.

Exploration in the Gulf of Mexico culminated in 2005 with the conclusion of a 35-day cruise by the exploration vessel *Uncle John*, which sampled and analysed hydrate bearing sediments at two sites known as Atwater Valley 14 and Keathley Canyon 195 (US DoE, 2008a). A key outcome of this programme was successful demonstration of the capacity to accurately predict hydrates occurrences from seismic data; an important addition to helping locate gas hydrates in the future. Additionally, the US DoE actively participates in hydrates research and exploration worldwide.

More information on hydrates activity in the US may be found in Appendix 4.

4.1.2 Canada

Natural Resources Canada, a department of the Canadian government and encompassing the Geological Survey of Canada, are responsible for the exploration and development of Canada's gas hydrate resources. Although their motivation for gas hydrate exploration is not founded in energy or economic security, Canada continues to actively survey both on- and offshore hydrate deposits in the Mackenzie Delta, the Northern Cascadia Margin and the area around Vancouver Island so as to better delineate economic resources. Current Canadian hydrate estimates are of the order of 1,550-28,600 TCF gas in place (Majorowicz and Osadetz 2001), with 311 TCF occurring in the Beaufort/Mackenzie Delta (Osadetz and Chen 2005). Canadian research funding is of the order of US$2 million/year over four years (Osadetz et al 2005).

The research programme at Mallik has involved some 265 scientists from more than five countries (including Japan, Canada, USA, Germany and India), who together completed more than 63 separate research programmes. In April 2008, the production test well at Mallik successfully produced commercial quantities of gas over a 6 day production run.

Plays	Mean Estimates (Trillion Cubic feet. Tef)	Percentage Of Total U. S. Resource
Atlantic Ocean Province	**51,831**	**16.1**
- Northeastern Atlantic Ocean Play	30,251	9.4
- Southeastern Atlantic Ocean Play	21,580	6.7
Gulf of Mexico Province	**38,251**	**12.0**
- Gulf of Mexico Play	38,251	12.0
Pacific Ocean Province	**61,071**	**19.1**
- Northern Pacific Play	53,721	16.8
- Southern Pacific Play	7,350	2.3
Alaska Offshore Province	**168,449**	**52.6**
- Beaufort Sea Play	32,304	10.0
- Bering Sea Play	73,289	23.0
- Aleutian Trench Play	21,496	6.6
- Gulf of Alaska Play	41,360	13.0
OFFSHORE PROVINCES TOTAL	**319,602**	**99.8**
Alaska Onshore Province	**590**	**0.20**
- Topset Play-State Lands & waters	105	0.034
- Topset Play-Federal Waters	43	0.013
- Fold Belt Play-State Lands & Water	414	0.13
- Fold Belt Play-Federal Waters	28	0.011
ONSHORE PROVINCES TOTAL	**590**	**0.20**
UNITED STATES TOTAL	**320,192**	**100**

Figure 4.1: USGS estimates of the United States in-place gas resources within gas hydrates (from US DoE 1998a)

4.1.3 Japan

A major leader in hydrate exploration and assessment, Japan's research budget has been estimated at approximately US$50 million per annum by US DoE (Osadetz et al 2005), a research effort that until recently exceeded the budgets of all other national programmes combined. The Japanese National Oil and Gas Company ('JNOC', now the Japanese Oil, Gas and Metals National Corporation 'JOGMEC') have had an early and active involvement in the Mallik production test operation.

A seven-year exploration phase followed an initial hydrates discovery in 1999. This exploration programme yielded what is thought to be the world's largest single offshore hydrate deposit (39 tcf) in the Nankai Trough in 2001. For Japan, this confirmation of indigenous hydrocarbon resources was sufficiently motivating to embark on a 15-year hydrate development plan, which anticipates beginning commercial production in 2016. A short but successful production test at the Mallik site using conventional technology in April 2008, though tested in an onshore setting, has further stimulated planning in Japan for offshore hydrate production. While the timing of any future Japanese offshore production test is uncertain, its drilling programme continues.

MITI/JOGMEC studies have estimated that Japan possesses an estimated hydrates resource endowment of 1,7665 tcf (Osadetz et al 2005).

More information on hydrates activity in Japan may be found in Appendix 4.

4.1.4 India

India, the fifth of the 'big five' major players in hydrates exploration established its programme in 2006 following the successful conclusion of a 4 month resource estimation programme of the Krishna-Godavari and Andaman-Nicobar islands in using the research vessel JOIDES Resolution. The results of this expedition were very positive for the Indian National Gas Hydrate Programme (NGHP), with USGS calling the discovery "some of the richest marine gas hydrate accumulations ever" [1]. The exploration programme also established the existence of a fully developed gas hydrate system in the Mahanadi basin off the Bay of Bengal. These discoveries have led to the establishment of a gas hydrates 'mission' in India, one step behind the establishment of a ministry for hydrates (Mukherjee, pers. comm. 2009).

Estimates by India's Oil and Natural Gas Corporation (ONGC) in 1997 suggested that the

1 http://energy.usgs.gov/other/gashydrates/india.html. Retrieved 15th April 2009

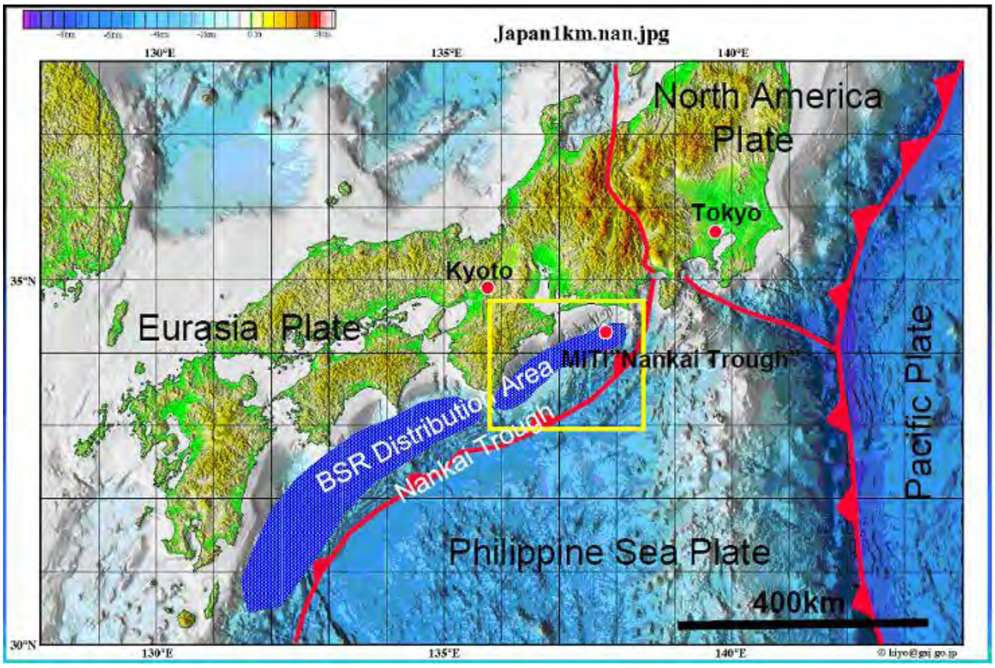

Figure 4.2: Map of Nankai Trough hydrate resource area (USGS)

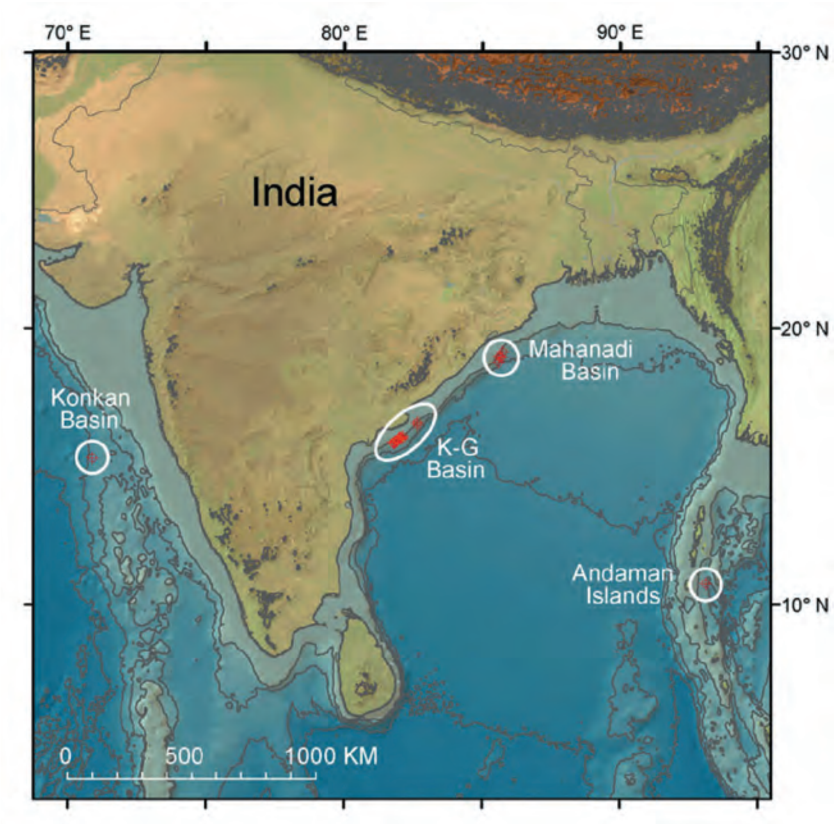

Figure 4.3: Map of key hydrate deposits explored during the Indian NGHP Expedition 01 (USGS)

size of India's in-situ resources at around 4,307 tcf (Osadetz et al 2005). The reported total budget of the Indian programme is US$56 million over five years. More information can be found in Appendix 4.

4.1.5 South Korea

South Korea's recent discovery of gas hydrates in the Ulleung Basin region of the East Sea (Sea of Japan) has greatly encouraged further exploration and development by that country. Estimates of research budgets are uncertain but could be as high as $US50 million/year. As much as US$67 million has been expended to date in initial exploration activity and the South Korean Government has earmarked a further US$243.5 million for the project until 2014.

The Korean discoveries represent approximately 30 years of that nation's current natural gas consumption. Of particular interest in the Korean situation, exploration and development is hindered by an ongoing territorial dispute between Japan and South Korea over the sovereignty of Dokdo/Takeshima island and the surrounding waters. Preliminary Japanese surveys suggest that the hydrate deposit in this region is even more promising than the Nankai Trough deposit, if not for size then for ease of potential extraction.

More information on hydrates activities in South Korea may be found in Appendix 4.

4.1.6 Other Regions

The successes of these exploration efforts have inspired many other nations to begin investigation of their own territorial waters in the hope of finding hydrate deposits, including New Zealand. In 2007, China reported extracting hydrate-bearing core samples from the South China Sea and now have a major research programme underway. Russia, Norway and Chile have also identified potential or confirmed hydrate resources. Other known deposits have vague territorial delineation, such as in the Bering Sea and the Atlantic Outer Continental Shelf.

4.2 CHARACTERISATION AND APPRAISAL

As with conventional oil and gas resources, economic extraction of a hydrate deposit will require a unique combination of specific parameters. These include all petroleum system components and favourable economics and recovery potential (Hunter 2004). Fundamental to this is a characterization and appraisal of the field in question. This involves identifying the geographical, geological, physical and chemical properties of the field, and how these properties change over the area of the field (i.e. reservoir heterogeneity) and the anticipated duration of extraction. By determining these parameters, an economic evaluation of the cost of extraction and the value of the resource can be made.

Detailed surveys of several major gas hydrate deposits have been undertaken to refine initial estimates and to more accurately determine technically recoverable (TRR) and economically recoverable (ERR) resources (Boswell 2005). These surveys make use of advanced scientific tools, from bottom-simulating reflectors (generated by seismic surveys) to determine the structure and density of the sea floor and hydrate-containing sediments, to Raman laser spectroscopy and 13C-NMR for characterizing the extent of the hydrate saturation and the composition of the stored natural gas.

Some examples of notably recent work in this area, presented at the 6th International Conference on Gas Hydrates in July 2008, are summarised below. These are illustrative of the extent of investigations being undertaken internationally to improve understanding of methane hydrate resource potential.

4.2.1 Barrow Gas Field, Alaskan North Slope (after Walsh 2008)

The Barrow Gas Fields are an existing resource site on the North Slope Borough of Alaska, a region with abundant hydrocarbon resources. An investigation was conducted in order to quantify the resource potential of the gas hydrate layer associated with the developed fields. BP Exploration Alaska headed the investigation.

The study consisted of seismic survey measurements, core logging and temperature measurements, and modelling the results to determine the local hydrate stability zone in relation to the geography of the area; and consequently the optimal production parameters for the field.

The investigation was able to determine that the field was supported by an external source of pressure, indicating the presence of an aquifer running through the hydrate zone or some hydrate decomposition in situ. This evidence was used to construct a model of the hydrate zone that could later be used for anticipating the gains from methane recovery from hydrate.

4.2.2 Offshore India Methane Hydrate Deposits (after Kumar 2008)

Several gas hydrate deposits have been mapped and sampled from four locations from both the east and west coasts of India (Figure 4.3). Of the 39 holes cored at 21 separate sites, 130 samples were taken and investigated using advanced laboratory techniques, including Raman laser spectroscopy, 13C-NMR and X-Ray Diffraction, in order to determine the molecular composition and structure of the hydrate deposits thereby, allowing a more accurate characterisation of the resource extraction potential and overall extraction economics.

It was found that all cores showed methane was the dominant gas component of the hydrate deposits, entrained as structure-I hydrate. This permits the assumption that dissociated water from hydrate extraction will amount to roughly 6 times the natural gas extracted. Further study revealed that of the two ‘cage’ sizes that the hydrate molecules form, the larger size was more than 99% occupied with methane, while the smaller cage was occupied between 75 and 99%.

4.2.3 Alaminos Canyon Block 818, Gulf of Mexico (after Latham 2008)

A seismic survey of this deep water (approximately 3000m) Gulf of Mexico site, revealed a bottom-simulating reflector at approximately 460m below the sea floor – a preliminary indication of a methane hydrate deposit. A core was drilled in order to confirm the hydrate presence.

Results from the core drilling between 3212m and 3475m below sea level (mbsl) indicated a gradual increase in methane concentration in associated gases up to around 20% at around 3300m, which then gradually decreased back to less than 1%. The core sample was also able to determine the range of geological materials in the sea floor and their average particle sizes, which is very important information for the potential drilling operator. Seismic p- and s-wave velocity measurement also established the average density of the sea floor layers.

4.3 ENGINERING AND PRODUCTION

In addition to the above several industry and research groups have begun actively investigating the engineering and production methods behind methane extraction from hydrates. Whilst conventional hydrocarbon extraction techniques are directly applicable to methane recovery, the particulars of well performance and bottom hole completions has emphasised in-situ dissociation techniques involving depressurisation, thermal injection and inhibitor injection. The success of production testing at Mallik has been an important milestone for evaluation of these techniques and the likely production issues that could govern commercial operation and recovery.

The Mallik site in the Mackenzie Delta, seen in Figure 4.4 from the USGS website[2], has become the poster-project of hydrate extraction development (Yamamoto 2008). Following initially successful trials in 2002, the Mallik project has operated as an internationally partnered production test well programme between seven participating entities. The Winter 2002 trial at Well 5L-38 produced 470m of natural gas over five days, using well depressurization coupled with thermal stimulation (injecting hot water or steam into the well to promote decomposition). This was the first trial of natural gas production from a hydrate reservoir.

Following the reestablishment of the older 2L-38 well, a second trial in the winter of 2007 lasted for 60 hours, with a continuous production of 830m of gas over a 12.5 hour period. This trial used only well depressurization as an extraction process, omitting the previous use of thermal stimulation.

A third trial at the same well in March 2008 resulted in the world's first continuous production run, producing a total of 13,000m of gas over a six day period, with 2000-4000m produced per day.

To date, Mallik has been the only successful

2 Retrieved from http://energy.usgs.gov/other/gashydrates/mallikmap.html, 19th February 2009

Figure 4.4: Mallik location map (USGS)

gas-from-hydrates production trial, although many more are in the pipeline, including a planned trial to be run by ConocoPhillips at a site on the Alaska North Slope, to test carbon dioxide injection and sequestration as a revolutionary extraction technology (US DoE 2008b). The technology, proven to have some success at laboratory scale, is particularly appealing because the carbon dioxide injection process creates heat through the chemical reaction of formation of CO_2-hydrates. This heat is in turn delivered to the existing methane hydrates, improving methane recovery. It also allows carbon dioxide to be sequestered in a thermodynamically stable way.

The first phase of the 27-month project commenced in October 2008 and aims to find and secure a suitable location for the field test. Following a period of detailed planning and numerical modelling, a field trial of the laboratory-verified process is planned for initiation in January 2010.

As previously indicated, it is predicted that the first offshore pilot and commercial scale production tests could well take place in the Nankai Trough off Japan's main islands. Simulation analysis based on the Mallik test data and applied to one concentrated zone of the Eastern Nankai Trough reveals that the potential gas production rate from a single well using just wellhead depressurization could exceed 50,000 m3/day (MH21 2008). Japanese researchers are also actively involved in developing new production methods, including sea floor mining and Low-Dose Hydrate Inhibitor (LDHI) Injection, which involves injecting known hydrate inhibitors such as methanol and ethylene glycol into the wellbore to stimulate hydrate decomposition.

Japan leads the way in this area of hydrate extraction technology owing to their long-term involvement through JOGMEC with the Mallik trials. Although India and South Korea have declared their intentions to develop hydrate extraction technology through similar industry partnerships, Japan's lead over the other major nations appears to be significant.

Overall, the development of extraction processes applied to gas hydrates is proceeding with vigour and considerable research has been generated internationally. Generally it has been found that no one method is superior in all circumstances and that the selection of the most appropriate method will depend on the physical and geological conditions present.

4.4 ECONOMICS

As will be obvious from the previous discussion, given the state of the industry and scientific knowledge of gas hydrate production, there is no simple answer to the question of the likely commercial viability if gas hydrates recovery and production. Every

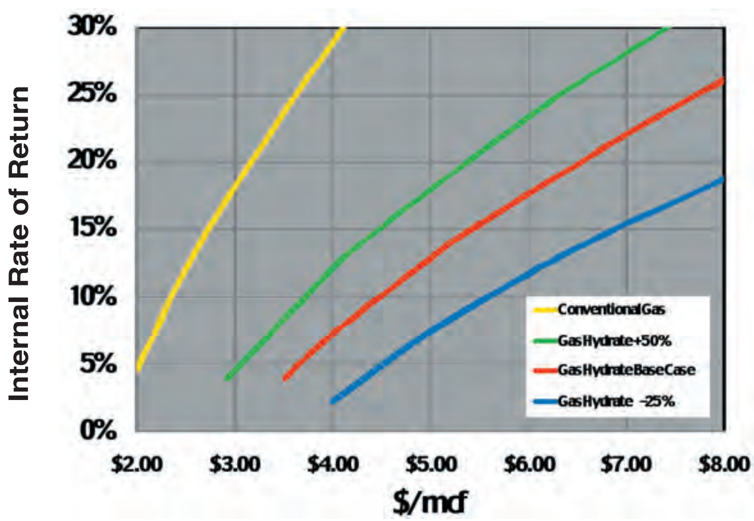

Figure 4.5: Indicative internal rates of return for a 500MMscf/d hydrate development. No royalties pre-tax. (Hancock 2008)

field development will stand on its own merits and commercial drivers will differ according to market and regional energy security issues. Industry itself remains very much silent on the issues of commerciality until technical viability is further proven and demonstrated.

The Gas Hydrates Economics Working Group, a collaboration between several North American university, research and government participants, has perhaps undertaken some of the more robust analysis of the requirements for commercial production. Their analysis, which draws on the results and learnings from different North American research programmes as well as industry Gulf of Mexico experience, aims to provide a comparative assessment of gas hydrate and conventional gas field development (Hancock 2008).

The key issues identified are the realities of having to operate gas hydrate fields below the typical abandonment pressure for conventional gas reservoir production, the much higher water production rates that exist and flow assurance from wellhead to production.

Preliminary findings and analysis undertaken by the group suggests that the potential for commercial hydrate production is very encouraging. Whilst the straight up economics of hydrates production will always be less than that from a comparable conventional gas reservoir, the absence of any apparent barriers to using conventional technology, and the advancing knowledge of deep water production in inherently unstable conditions offers considerable prospect for future commercial demonstration of the technology. Security of supply issues and likely government incentives in support of national energy policy will be used to offset the marginal economics.

The economic horizons derived for a stand alone deepwater gas hydrate development of 500 MMscf/d nominal capacity are set out in Figure 4.5. A more comprehensive discussion of the economic feasibility of an offshore New Zealand gas hydrates development is provided in Chapter 5.

4.5 LESSONS FOR NEW ZEALAND

4.5.1 New Zealand Capacity to Support a Gas Hydrates Resource Programme

New Zealand's motivation in focusing on the potential of its hydrate resources arises from its substantial endowment, disproportionate to the scale of our economy, and the potential wealth that would become available from unlocking the resource potential. It is not realistic to anticipate that New Zealand will have the resources to autonomously advance commercialization of its hydrate resources. Compared to other similar economies, New Zealand lacks a state oil company as well as a base of large-scale industrial energy sector interests capable of investing in such a project.

New Zealand does, however, have the capacity to support and participate in significant resource development opportunities. Large companies engaged in production and wholesale supply of thermal fuels include Shell (multi-national), Todd (private New Zealand firm), OMV (Austrian), Origin (Australian public company, also cornerstone shareholder in Contact Energy), Vector, (mainly consumer trust-owned); and State Owned Enterprises (SOEs) such as Genesis Energy, Mighty River Power, and Solid Energy. It is also worth noting that several Asian companies are already engaged in oil and gas exploration (and in one case, production) in New Zealand – Japan's Mitsui, PTTEP of Thailand and South Korea's Hyundai Hysco.

It is unlikely that any individual or coalition of the above would move aggressively to stimulate gas hydrate appraisal without considerable stimulus from central government – the likelihood of capturing due benefits in a reasonable timeframe is too uncertain. Even in much larger and resource-oriented economies such as Australia, Canada and the USA, it has only been with government (in some cases e.g. Mallik, foreign) leadership that effective initiatives such as Joint Industry Projects have secured some industry participation.

New Zealand's proprietary and strategic interests in our marine gas hydrate resources are well secured by the Crown Minerals Act, and our rights under the United Nations Convention on Law of the Sea. These frameworks also call for commercial development and thus open up the opportunity for New Zealand to take a proactive stance in development of its hydrates resource.

Opportunities have already arisen for foreign participation in New Zealand's science effort (notably the German RV Sonne cruise in 2007), and another major international campaign to study four possible gas hydrate fields with state-of-the-art geophysical, geochemical and microbiological techniques is already planned (i.e. RV Sonne, 2011). Extending these efforts to be more strongly aligned with international activities seems an obvious way forward.

4.6 ALIGNMENT WITH INTERNATIONAL ACTIVITIES

In nearly all cases, international hydrate development activities have involved a consortium of commercial, governmental and academic groups, often from many different countries. These collaborations have been responsible for the major hydrate discoveries in North America and the first production trial at Mallik in the Canadian Northwest Territories. Other bilateral arrangements exist between countries participating on smaller research and exploration projects.

New Zealand's future success in developing the methane hydrate resource will rely on similar international cooperation with experienced organizations. Outlined below are summary details of three such ventures.

4.6.1 Mallik 2002 Production Well Test Programme - JOGMEC

This international science and engineering research partnership, managed by the Geological Survey of Canada, brought together the Japanese Oil and Gas Exploration Company (JAPEX), the then - Japanese National Oil Company (JNOC, now the Japanese Oil, Gas and Metals National Corporation: JOGMEC), the US Geological Survey (USGS) and US Department of Energy/National Energy Technology Laboratory, along with several other contributors, to perform a production test on the known sub-permafrost hydrate resource. The success of this first test and the six years of research and development following it resulted in the consortium reforming for the world's first continuous production test. Using the knowledge gained from Mallik, JOGMEC's next objective is a successful production test offshore at a Nankai Trough site 50km off the Japanese coast, followed by the establishment of what will be the first offshore commercial hydrate production site in 2016.

4.6.2 Gulf of Mexico JIP – Chevron Energy Technology Company

The primary aim of the Gulf of Mexico JIP is to "develop technology and data to assist in the characterization of naturally occurring gas hydrates in the deep water GOM" [US DoE, 2008a]. It is strongly motivated by the interest in increasing safety associated with deep-water drilling in hydrate stability zones. Additionally, "the activities undertaken in the project will significantly advance hydrate science and the technologies employed in studying hydrates in the field, providing valuable tools and insights to researchers on many fronts of the methane hydrate issue, including hydrate's role in global climate and its long-term potential as a supply source for natural gas" [ibid.].

4.6.3 Alaskan North Slope JIP – ConocoPhilips and BP Exploration Alaska

The Alaskan North Slope is an existing onshore hydrocarbon development with the potential to become the first onshore hydrates production site, owing to the existing expansive and well supported infrastructure. A site in the North Slope field has been chosen for a ConocoPhilips hydrate extraction trial using carbon dioxide injection (US DoE, 2008b). As this method of extraction is still very much at a development stage, the technical risks are considerable and thus some doubt exists as to the likelihood of a successful outcome.

4.6 Concluding Remarks

Given the similarity of New Zealand's resource potential compared to Japan's, involvement with JOGMEC's consortia and future projects will yield indispensable and appropriate knowledge and skills that can be applied to New Zealand projects.

The information collected by this ongoing investigation will be directly applicable to the recovery of hydrate resources in New Zealand; consequently a New Zealand representative in the JIP would be highly desirable.

Involvement in the North Slope JIP would potentially yield strong political capital and set a positive example globally for the recovery of fossil fuels without the environmental burdens so associated. Involvement would also introduce New Zealand to potential customers of any hydrate-sourced natural gas exports, such as South Korea, who with modest hydrate resources under territorial dispute may seek security in a friendly nation's supply.

5. OPPORTUNITY ANALYSIS

5.1. HYDRATES WELL DEVELOPMENT PLAN

5.1.1 Introduction

Transfield Worley Services were commissioned to produce a high level well development plan for the Wairarapa gas hydrate 'sweet spot' site on the East Coast of the North Island of New Zealand (covered in previous chapters).

Transfield Worley Services' extensive and ongoing role in the development of the Taranaki exploration and production sector was expected to provide the most robust and comprehensive data on New Zealand oil and gas projects for the well development plan and for the subsequent economic analysis component of this study.

5.1.2 Methodology

The prospective location for the well development is at the Opouawe Bank (referred to commonly as the "Wairarapa site") illustrated in Figures 5.1 and 5.2, where a BSR sweet spot and numerous methane-rich fluid seeps occur. The Wairarapa 'sweet spot' site is located approximately 22km offshore of the south Wairarapa Coast. Hydrates have been identified from seismic surveys approximately 300m below the seabed at water depths of 1000m (Pecher and Henrys 2003); and gas hydrate has been sampled from the sea floor at this location by NIWA's vessel *Tangaroa*.

A 'sweet spot' with estimated hydrate volume of between 0.04 to 0.5 tcf (Pecher 2006), this site is expected to be a model candidate for exploring the future development and production of methane from hydrates in New Zealand due to hydrate concentration at the site and its proximity to shore and a major demand centre in Wellington. Although this site has been well surveyed and is relatively well understood from geological, geophysical, ecological and oceanographic perspectives as seen in Figure 5.2 (Barnes et al., in press; et al., 2009; Schwalenberg et al., submitted; and others), it has yet however to have been subjected to ground-truthing or resource characterisation. Better quality seismic data are still required from this location. This lack of certainty is reflected in contingency rates that have been applied to the cost estimates in this analysis.

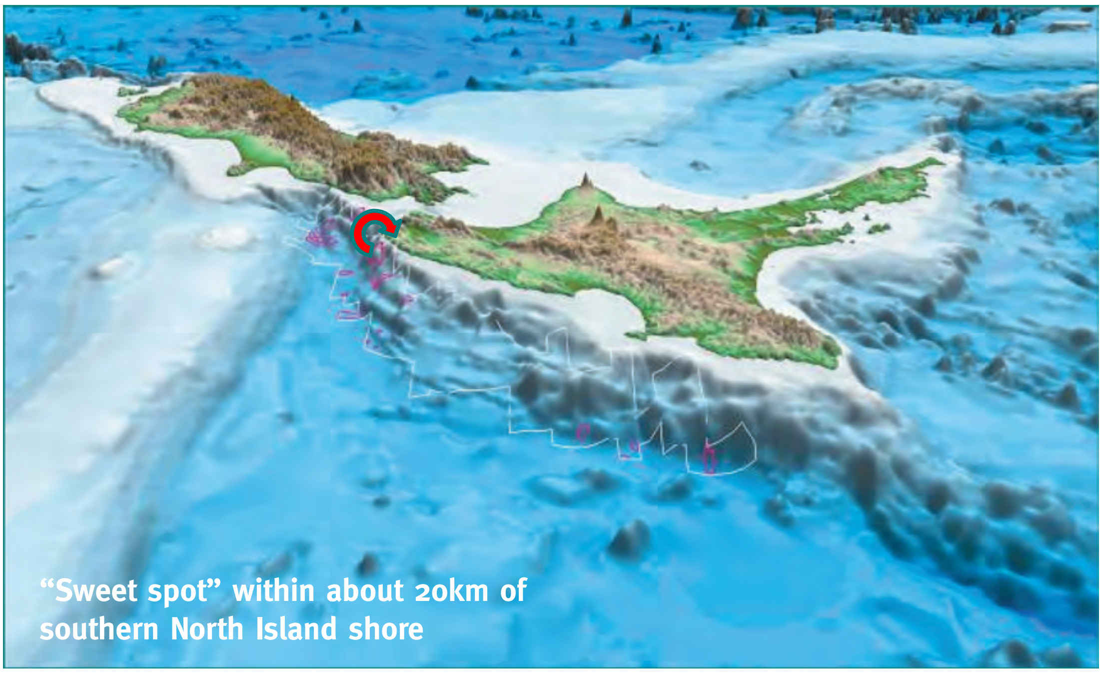

Figure 5.1: Wairarapa (Beggs, Hooper and Chong 2008)

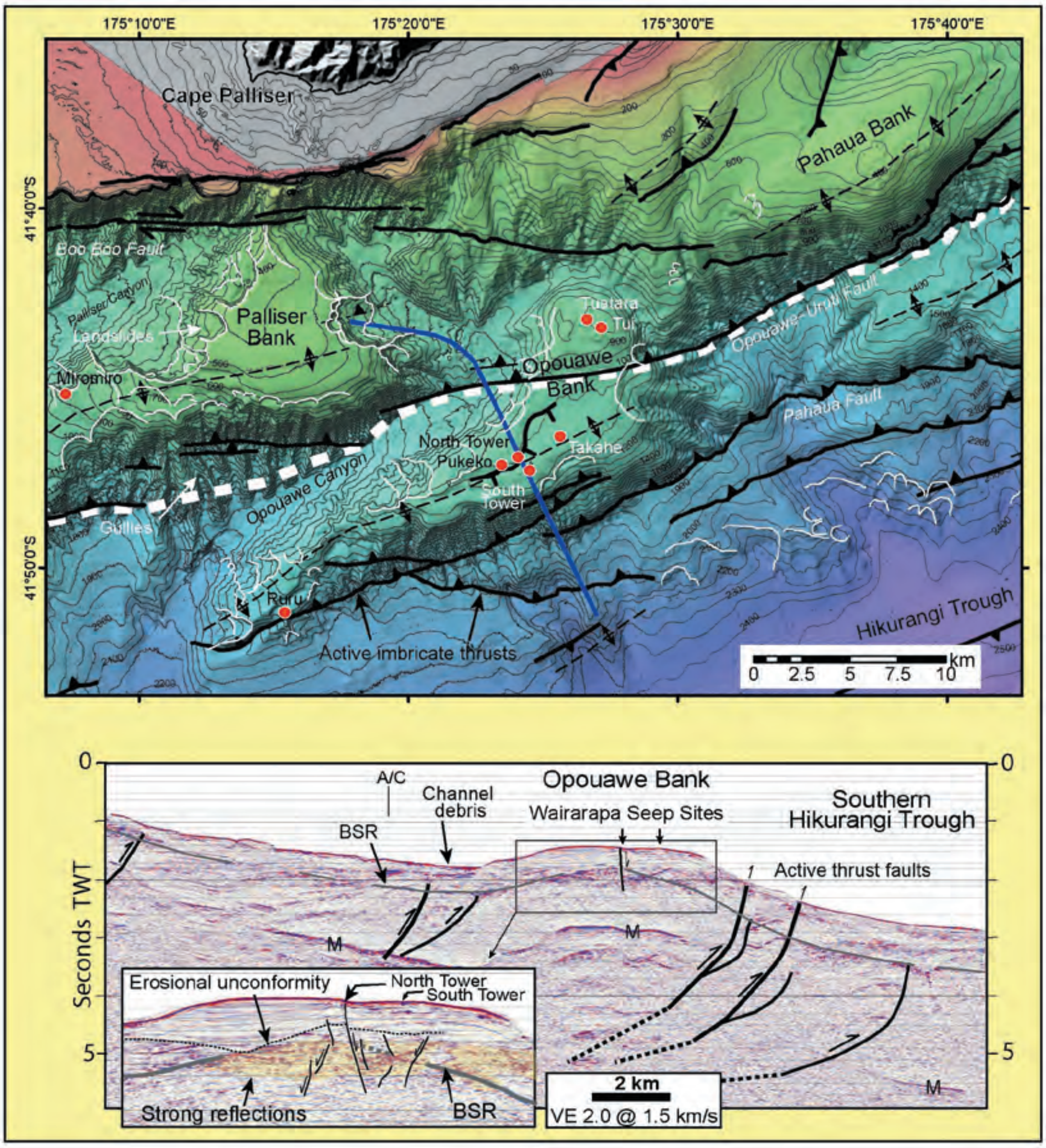

Figure 5.2: A. Major tectonic and geomorphic features associated with the Wairarapa seep sites at Opouawe Bank. Bathymetry. From Barnes et al. (in press).

The basis for the Transfield Worley Services well development plan was Hancock's paper to the 2008 New Zealand Petroleum Conference, which illustrated the differences between a conventional gas and a modelled hydrates well development.

Cost estimates were then derived independently from Transfield Worley Services' cost database for New Zealand oil and gas projects, and complemented where required by recourse to their international databases.

5.1.3 Preliminary New Zealand Hydrate Well Development Plan

A simplistic gas hydrate well development plan is illustrated below. The rationale and various considerations taken into account in bringing this scheme together are attached as Appendix 6.

Preliminary Development Plan

The 3 phases of development envisaged for the Wairarapa well development plan are summarised in Table 5.1. The development schematics underlying this plan are provided in Appendix 6.

Phase 1: Preliminary Proving/Testing Phase

This phase is built around a 9 month programme involving a blue-water rig and associated support vessels. This approach provides a degree of flexibility to the project by allowing mobility and flexibility to drill new

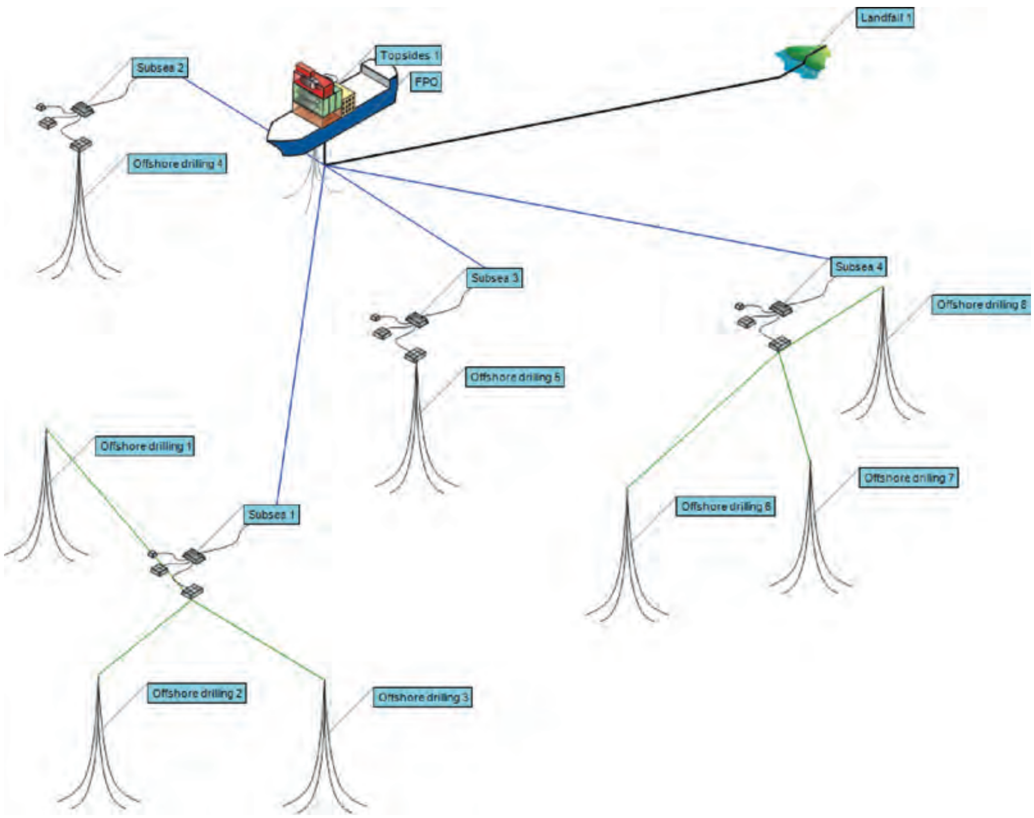

Figure 5.2a: Notional Gas Hydrate Field Development Plan (Hancock 2008)

wells if required. It is also assumed that the rig will have onboard the requisite process testing equipment. Cost estimates for this phase are provided in Table 5.2.

In this analysis, a rig rate of $250k per day has been assumed. The historical daily rate for a rig capable of working at the 3000-4000ft depth range has varied from US$80 per day in 2004 to US$420k per day in late 2008 when oil was over $150/bbl. but has slipped recently to $320k per day and is not unreasonable to expect that a lower rate could be negotiated f me as envisaged.

Phase 2: 10 PJ Appraisal and Testing

In this phase of development, a 10 PJ facility intended to be scaled up to 150 PJ over a ten year time frame is envisaged. The cost estimates provided in Table 5.3 include costs for equipment at both scales, which will be installed at the commencement of the development. This approach addresses anticipated difficulties of getting a work barge on site when it may be required (due to strong demand elsewhere in the world) and also mobilisation/demobilisation costs for the work barge, which can easily exceed US$25m before any work is actually commenced in New Zealand waters.

This 10 PJ scale facility is expected to service a single cluster of 6 wells, with the resulting hydrate derived methane pumped onshore for use in the domestic market. A new pipeline will be required to connect to the 8in grid serving Hawkes Bay.

PHASE	COST ESTIMATE (real 2009 NZ$)
1. Preliminary proving and testing, including site selection	NZ$322m
2. 10 PJ appraisal and testing	NZ$1,362m
3. 150 PJ development and production	NZ$2,879m
Total	**NZ$4,563m**

Table 5.1: Gas Hydrate Capital Cost Estimate Summary

PHASE 1	DESCRIPTION	COST ESTIMATE*
1.1 Appraisal & Testing	Appraisal for test programme	$12m
1.2 Preliminary Drilling & Testing	2 offshore wells @ $5m ea; Single blue-water drilling rig on-station for 9 months @ $250,000/day; Two support vessels for 9 months @ $50,000/day;	$310m
Total		**$322m**

** NZ$ in 2009 Real Terms*

Table 5.2: Capital Cost Estimates for Phase 1 – Preliminary Proving & Testing

Phase 3: 150 PJ Development and Testing

Over a 10 year time frame, production will be ramped up to 150 PJ utilizing the processing equipment already installed. An additional 4 clusters of 6 new wells, or a total of 30 wells, will be drilled to meet this rate of production. It is also assumed that due to the characteristics of the hydrate reservoir, wells will need to be replaced on a 10 yearly basis and have been costed accordingly, as set out in Table 5.4.

Basic Process Description

The basic process is to reduce the pressure in each well by removing gas and liquid, thus causing more hydrate to dissociate into gas and free water. This process will be enhanced by chemicals and the water produced will also need to be removed. Process sketches for both offshore facilities and at the landfall receiving station are provided in Appendix 6.

Basic Subsea Well and Pipeline Layout

The proposed layout of the subsea wells for both the 10 PJ and 150 PJ cases is based on that suggested in the Hancock report and shown in Appendix 6 and Figure 5.2a previously.

Selection of Production "Platform"

With water 1000m deep, conventional offshore jacket supported structures, like Maui for example, are out of the question. Three potential proven solutions could be employed: a) a tension leg platform (TLP); b) a floating production unit (FPU), which is basically a moored, converted tanker; or c) a SPAR. As there isn't a great difference in cost between

PHASE 2	DESCRIPTION	COST ESTIMATE*
2.1 Appraisal & Development	Project Management, Engineering & Quality Control; Operations and commissioning costs; Insurance	$66m
2.2 Drilling	Well engineering, subsurface studies and completion of a single cluster of 6 wells; Mobilisation and demobilisation of the drilling rig(s);	$476m
2.3 Offshore Facilities	Location on-site of the topside facility; Construction of sub-sea pipelines and umbilicals to topside facility and onshore;	$714m
2.4 Onshore Facilities	Construction of an onshore receiving station and 1st gas pipeline to connect to the National Grid	$106m
Total		**$1,362m**

** NZ$ in 2009 Real Terms*

Table 5.3: Capital Cost Estimates for Phase 2 – 10 PJ Appraisal & Development

PHASE 3	DESCRIPTION	COST ESTIMATE*
3.1 Appraisal & Development	Project Management, Engineering & Quality Control; Operations and commissioning costs; Insurance	$132m
3.2 Drilling	Well engineering, subsurface studies and completion of a further 4 clusters of 6 wells; Mobilisation and demobilisation of the drilling rig(s)	$1,796m
3.3 Offshore Facilities	Sub-sea pipelines	$221m
3.4 Onshore Facilities	Construction of the 2nd gas pipeline to connect to the National Grid	$320.3m
Total		**$2,879m**

** NZ$ in 2009 Real Terms*

Table 5.4: Capital Cost Estimates for Phase 3 – 150 PJ Development & Production

all three, a decision was made to only cost out a TLP. More information on the differences between the platforms may be found in Appendix 6.

Technical and project data on worldwide applications of SPARs and TLPs, including deployment time frames from discovery to first gas, may also be found in Appendix 6.

Development Schedule

The similarity of the technology envisaged for this hydrates development with other conventional offshore projects utilizing TLPs, FPUs or SPARs, the time scales given in Appendix 6 provide a good indication of expected project timing.

A small to mid-sized TLP or SPAR is envisaged for the 10 PJ scaling up 150 PJ production facility. Hancock proposed using a FPU (floating production unit) which is also practical and feasible.

Although considerably more study will be required to arrive at an optimal selection for a topside facility, the hard data tabulated in Appendix 6 suggests that for a small to medium TLP, a 30 month study period will be required to arrive at a final investment decision.

Furthermore, the data also suggests that the total project duration from discovery till first gas under the assumptions above is about 70 months.

5.2 ECONOMIC ANALYSIS

5.2.1 Introduction

A national economic cost-benefit analysis has been undertaken to demonstrate the potential for the development of New Zealand's gas hydrate resource endowment to provide a viable, economically competitive alternative or replacement for indigenous and imported fuels/gas. The full study is provided as Appendix 7.

This analysis is also intended to demonstrate the potential economic value of government policies designed to accelerate the development of New Zealand's hydrate resource, and to determine if the export of methane from hydrates as LNG is likely to add further value.

5.2.2 Methodology

The economic analysis adopted for this study is based on the methodology outlined in Treasury's Cost Benefit Analysis Primer[1], and utilised key parameters from MED's Cost-Benefit Analysis of the New Zealand Energy Strategy[2], including: a US$/NZ$ exchange rate of 0.54, an oil price of US$60/bbl and an international price for methane, derived from the LNG price formulae developed for MED by Gary Eng[3]. Internal transfers such as

1 The Treasury, 2005. Cost Benefit Analysis Primer v1.12. Url: http://www.treasury.govt.nz/publications/guidancecostbenefitanalysis/primer

2 Energy Modelling Group, MED, 2007. Benefit-Cost Analysis of the New Zealand Energy Strategy. Url: http://www.med.govt.nz/templates/MultipageDocumentTOC____31983.aspx

3 Eng, G. 2008. A Formula for LNG Pricing [Updated 26

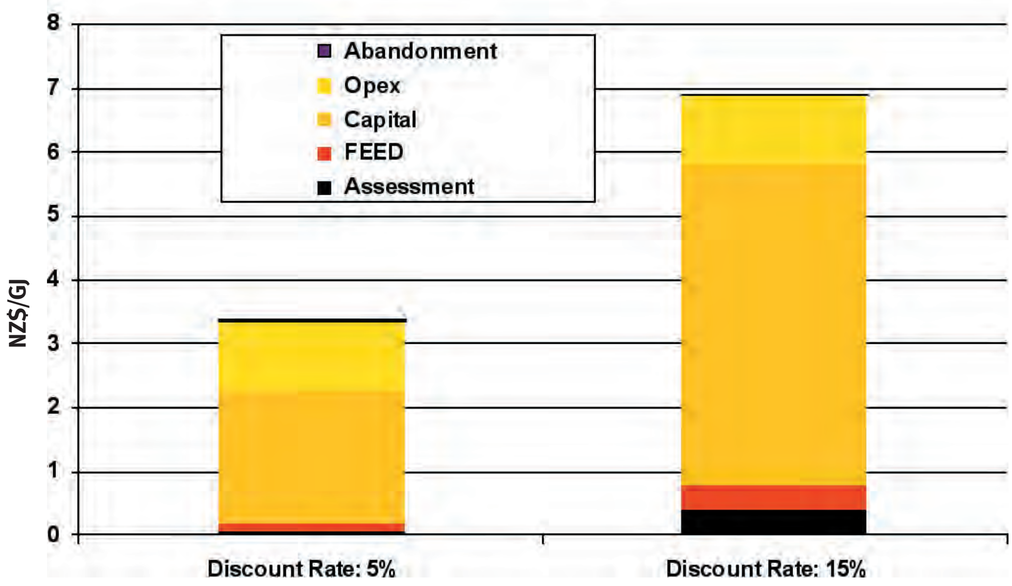

Figure 5.3: Comparison of Unit Cost of Production for a 300 PJ Development at different discount rates

royalties, taxation and payments between commercial entities involved in the project scenarios have, however, been excluded from the analysis. Economic costs and benefits throughout the analysis are in real 2008 NZ dollars and exchange rates have been held constant.

Simplified scenarios using fixed methane values and assumed scales of development at the 10 PJ, 150 PJ and 300 PJ have been used to illustrate the impact of key assumptions and uncertainties on the economic analysis. Additionally, a 'composite' scenario, which envisaged the development of a 10 PJ 'proving project' as a precursor to a major 300 PJ facility serving both domestic and export markets within a 10 year time frame, has been used to illustrate a probable staged development pathway.

The cost estimates used for the scenarios have been derived from Hancock's presentation to the 2008 New Zealand Petroleum Conference[4] and independently corroborated by Transfield Worley Services using their cost database for conventional sub-sea oil and gas field developments in Taranaki. These estimates probably reflect the most advanced gas hydrate estimates for a New Zealand development currently available in the public domain. However, it should be noted that in the absence of a commercial precedent upon which to base these costs estimates, they are subject to considerable uncertainty.

Unit costs of production have been calculated for both a hydrates scheme and a comparable conventional offshore natural gas development. These have been calculated at the production price the project would have to receive for the methane to achieve an economic internal rate of return of 5% or an arbitrarily selected 'commercial' rate of 15% on a real dollar, before tax basis. Figure 5.3 illustrates the difference in calculated unit cost of production using the same costs but at the two different discount rates for a 300 PJ hydrate development. By comparison, the unit cost of production for indigenous natural gas has been calculated at NZ$2.50/GJ.

We note that this analysis has not investigated the price effect on gas consumption, and it is has been assumed that the availability of gas hydrate will not change the current rate of consumption. Any national benefit arising from higher consumption of gas will be relatively small compared to the benefit arising from reduced gas costs, and thus will tend to underestimate the net benefits somewhat.

5.2.3 Development Scenarios

Four scenarios have been developed to

November 2008], Ministry for Economic Development. Url: http://www.med.govt.nz/templates/MultipageDocumentTOC____39562.aspx

4 Hancock, S. 2008. Development of Gas Hydrates. Presentation to the 2008 New Zealand Petroleum Conference.

Scale	Hydrate Disassociation[5]	End Use	Basis for inclusion
10 PJ pa	1.5m tonnes	Feedstock for 200MW scale thermal generation or petrochemicals	To illustrate the economics of small scale development, where it is likely that hydrates will be competing against indigenous natural gas. To provide the basis for costing the "proving" phase of the staged development.
150 PJ pa	22.5m tonnes	Equivalent to the entire New Zealand gas market (excluding existing methanol capacity)	To compare production of hydrates with the importation of LNG, the most likely replacement fuel in a longer term supply constrained domestic gas market.
300 PJ pa	45m tonnes	Will provide 5.4m tonnes of methane for domestic use and export as LNG	To illustrate the economics of exporting methane extracted from hydrates
Composite		10 PJ proving project expanding to 300 PJ production over 10 years	To illustrate an economically optimal hydrate development pathway

Table 5.5: Development Scenarios

demonstrate the anticipated economics of small and large scale production of gas hydrates and also any benefits from exporting methane.

Two cases have been used for the scenarios above to demonstrate the potential economic benefits from accelerating the commencement of production from hydrates by bringing forward the first production date of hydrates:

- The "business-as-usual" (BAU) case for each scenario assumes that the absence of specific initiatives to actively facilitate the development of New Zealand's hydrate resource would result in New Zealand receiving low priority from potential investors and energy companies, lag behind the development of hydrates in other larger economies and result in the country effectively becoming one of "the last cabs off the rank". This case assumes that hydrates production will not occur before 2040;
- The "accelerated development" case is intended to test whether there are potential economic benefits in accelerating the introduction of the technology, particularly when the 'backstop' alternative fuels for the New Zealand market are expected to be significantly more expensive.

A more detailed description of the key assumptions for the scenarios above is provided in Appendix 7.

5.2.4 LNG Prices

Methane produced from hydrates and exported to international markets will be shipped out of New Zealand as LNG or Liquefied Natural Gas. The value of this methane to the hydrates development project is the FOB price of the LNG, less the cost of liquefying the methane. As New Zealand LNG is likely to be shipped to the large East Asian markets, the FOB price in New Zealand will be the East Asian CIF price, less the freight from New Zealand to East Asia. It is also assumed that the CIF price of LNG in New Zealand will be similar to that in East Asia as the transport distances from likely suppliers will be of a similar magnitude, making the New Zealand FOB price equal to the CIF price, less the ocean transport costs to East Asia. This transport cost has been set at US$0.80/GJ, the same as the cost of liquefaction.

LNG prices used in this analysis have been derived from formulae published by Eng (2006, 2008) for MED[6], and are intended to provide a proxy value for the methane

5 Beggs, M. et al (2008). Gas Hydrates Road map. GNS Science Report SR2008/06

6 Eng, G. 2008. A Formula for LNG Pricing [Updated 26 November 2008], Ministry for Economic Development. Retrieved from: http://www.med.govt.nz/templates/Multi-pageDocumentTOC____39562.aspx;

Eng, G. 2006. A Formula for LNG Pricing: A Report prepared for the Ministry of Economic Development, May 2006

	US$/GJ	NZ$/GJ	
Exchange Rate: US$:NZ$	0.54		
Oil Price: US$/bbl	$60		
LNG Price Formula		Guandong	Current
LNG: CIF			
LNG: Import Price CIF*		9.10	16.77
plus Re-gasification Cost		2.31	2.31
Cost of imported gas into network		**11.41**	**19.08**
LNG: FOB			
East Asia CIF Price		9.10	16.77
less Freight NZ to East Asia	0.80	1.48	1.48
less Liquefaction Costs	0.80	1.48	1.48
Exports ex hydrate plant		**6.13**	**13.80**

Table 5.6: Methane Values Determined from LNG Prices

produced from hydrates. The two pricing methodologies quoted determine the CIF price in Japan under differential market conditions.

The 'Guandong' price reflects a historical price for LNG at a point in time when surplus supply forced the LNG price down to a level where its links to oil prices were weak. For the purposes of this analysis, the Guandong price is used to indicate a conservative lower boundary for LNG prices, although the likelihood is that LNG prices will trend higher. On the other hand, the 'Current' prices quoted for LNG are more reflective of the current and long term view of the supply and demand equation and are thus more strongly linked to the price of oil.

The CIF price derived for New Zealand provides an indication of the methane value as an alternative to imported fuels while the FOB price provides an indication of the export value of methane produced from hydrates.

A determination of the CIF and FOB prices is shown in Table 5.6 and these prices have been kept constant throughout the analysis.

Both the current and Guangdong formulae above have included the cost of re-gasifying the LNG in New Zealand, and have the US$/NZ$ exchange rate and international oil price as their principal independent variables. These were set at 0.54 and US$60/bbl. respectively, and both these variables have been tested in the sensitivity analysis.

5.2.5 KEY FINDINGS

Costs of Production

The principal costs assessed for the economic analysis were the expenditure on engineering development, appraisal of the hydrate resource, and all capital and operating costs throughout the life of the hydrate plant. The data for this study have been derived from Hancock (2008) and Transfield Worley (2009)[7].

No assumptions have been included in this analysis regarding the net cost of any carbon emissions resulting from hydrate use as it has been assumed that the project would be carbon neutral due to the replacement of natural gas and LNG by the methane produced from hydrates.

Hancock's comparison of estimated capital and operating costs for respective hydrates and natural gas developments at the 195 PJ per annum scale provided an insight into the relativity between hydrates and natural gas costs of production. These estimates were complemented by Transfield Worley Services, specifically for the 10 PJ and 150 PJ hydrate

7 Transfield Worley Services, 2009. Preliminary Development Plan: New Zealand Offshore Gas Hydrates. Unpublished Report prepared by John De Buerger for the NZ Centre for Advanced Engineering.

	NZ$ Million			
Scenario (PJ)	**10S**	**10C**	**150**	**300**
Hydrate				
Assessment	22	22	66	168
FEED	14	44	132	420
Capex	370	1300	4043	8391
Opex per annum	17	81	280	332
Abandonment	19	65	202	420
Gas				
Assessment			50	50
FEED			107	214
Capex			2142	4284
Opex per annum			102	205
Abandonment			107	214

*Table 5.7: Costs of Exploiting Hydrate Resource (*Note: Gas costs based on Hancock 2008 data for conventional well development)

scenarios. Due to the close corroboration between the Hancock & Transfield Worley Services estimates of the 150 PJ scenario, only one estimate has been used for the costs of the 150 PJ & 300 PJ scenarios, with due allowances for the differences in project scale.

Two scenarios have been considered for the 10 PJ scale development:

- Scenario 10 PJ/C: A Commercially Driven Scalable Proving Project

  This scenario is based around the staged development of a 10 PJ pa 'proving project' acting as a precursor to, and designed to be integrated into, a future commercial 150 PJ or 300 PJ development. Capital expenditure has been disproportionately weighted in at the front-end 10 PJ phase to allow for future capacity expansion. Under this scenario, the cost estimates are based on the development of a single initial cluster of 6 wells at the 10 PJ stage, increasing to an additional 4 clusters at the 150 PJ stage.

- Scenario 10 PJ/S: A Small Scale Stand Alone Project

  This scenario represents a stand-alone, small scale project, designed without cognisance of integration into future capacity expansion. While still based on an initial cluster of 6 wells, the overall capital costs are significantly lower than the previous commercially driven scenario as the processing and compression plant has been sized for a much lower output.

Whilst not included in the economic analysis, Transfield Worley Services also included cost estimates for a 9 month duration 'proof-of-concept' project based around the development and flaring of gas from 2 wells, using a blue-water drilling rig and two support vessels. The cost of this project was estimated at NZD$322m and more information may be found in Section 5.1 of this chapter and in Appendix 6.

Table 5.7 summarises the cost estimate data derived for each of the four scenarios.

Five consecutive cost categories were included in the analysis outlined in Table 5.7:

- Assessment: Includes the development of the hydrate extraction technology and the characterisation of the hydrate resource, and is assumed to be incurred over a ten year period prior to the commencement of engineering design.
- FEED: Set at 3% to 5% of capital costs, which is typical of large capital projects, and is assumed to be incurred over a three year period for the 150 PJ and 300 PJ scenarios, two years for the 10 PJ/C scenario and one year for the 10 PJ/S scenario.
- Capital: Provided by Transfield Worley and Hancock. Construction times of four years for the 150 and 300 PJ scenarios, three years

for the 10 PJ/C and two years for the 10 PJ/S scenarios have been assumed.

- Operating: Set at 4% to 7%, which is consistent with Hancock 2008's lump sum operating costs over a 25 year operating period, but adjusted for a larger contingency and higher degree of well maintenance compared to conventional gas well development.
- Abandonment: Set at 5% of capital costs in the year immediately after the last year of operation.

The unit costs of production for both hydrate-derived methane and natural gas under these assumptions are shown in Figure 5.4, but only for the 10 PJ/S scenario. The costs for the alternate 10 PJ/C project were more than twice as high as a standalone facility and have not been included in Figure 5.4. As previously discussed, the costs determined at a 5% discount rate represent the economic costs of production used in this analysis whereas those at 15% are indicative of commercial price points. Each of the 10PJ/C and 10 PJ/S scenarios have been included as the forerunner to the 300 PJ development in the composite scenario. Costs and hydrate production profiles are treated somewhat differently in each case:

- As the 10 PJ/S scenario is designed to be a "scientific" project, it will not be scaled for integration into the subsequent design of the expanded 300 PJ development. Consequently the total capital cost of the 10 PJ/S composite scenario will be $370 million during the first phase plus $8,391 million in the second phase. Conversely, the 10 PJ/C development is designed to be integrated into the final development so the total capital cost will be $8,391 million, comprising $1,300 million in the first phase and $7,091 million in the second.
- The construction time for the 300 PJ plant is reduced to three from four years when preceded by the 10 PJ/C development because of the high level of integration with the initial phase. A four year construction period for the 300 PJ facility is assumed with the 10 PJ/S initial phase.
- Hydrate production in the 10 PJ/C case will continue throughout the eight year period prior to the start-up of the 300 PJ plant as the initial phase has been designed for subsequent commercial development. However, hydrate production in the 10PJ/S "scientific" case is assumed to cease after two years, although subsequent production from the 300 PJ plant will also commence eight years after first production from the 10 PJ plant.

Competitiveness of Hydrates with Alternative Sources of Gas

An economic "internal rate of return" measure is used to determine the net benefit of avoiding the cost of natural gas supply by investment in hydrate technology development and subsequent hydrate plant capital and operations. This is summarised in Table 5.8 for the 10, 150 and 300 PJ per annum scenarios and illustrates the sensitivities of the derived rates of return for the base case assumptions to changes to assumptions in the analysis.

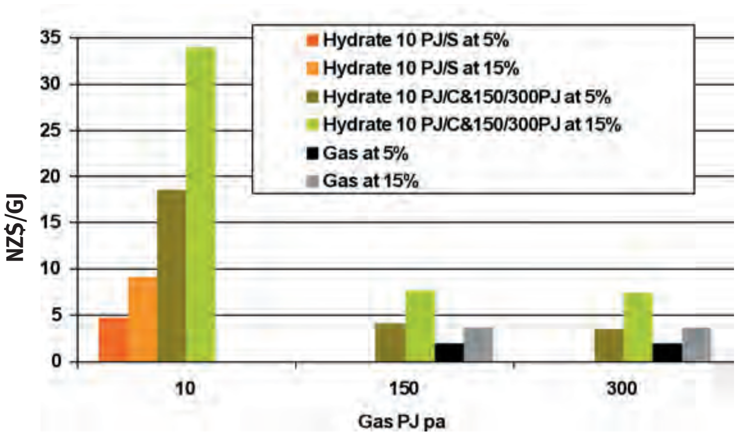

Figure 5.4: The average cost of production at different scales of production and rates of return (Producer price)

Scenario Size (PJ)	300		150		10 C	10 S
Export Component (PJ)	150		0		0	
Gas Value Basis	LNG		LNG		Domestic	
Cost of Production ($/GJ)	3.47		4.09		18.54	4.76
LNG Price Formula	Guandong	Current	Guandong	Current		
Internal Rates of Return (IRR)						
Base Case Assumptions	17.4%	26.9%	21.5%	30.1%	Negative	Negative
Sensitivities						
Development Costs + 100%	8.0%	16.5%	10.2%	18.5%	Negative	Negative
Domestic Gas Cost: $5/GJ	17.4%	26.9%	21.5%	30.1%	Negative	Negative
Oil Price: USD$20/bbl	10.0%	12.7%	15.1%	17.3%	Negative	Negative
Exchange Rate US$/NZ$: 0.85	11.1%	20.0%	14.0%	22.5%	Negative	Negative
Gas Value: Domestic	7.8%	16.3%	Negative	Negative	Negative	Negative

Table 5.8: Replacement of Gas by Hydrates - Internal Rates of Return

General conclusions that can be drawn from the above include:

1. Hydrate production will provide significant net economic benefits relative to imported gas. Hydrate derived natural gas has been valued against LNG in both the 150 and 300 PJ scenarios, resulting in economic internal rates of return of 30.1% and 26.9% respectively when using the current formula for LNG prices. The driver behind these high returns is the high value of LNG imports and exports (NZ$19.08/GJ and NZ$13.80/GJ respectively) relative to the cost of producing methane from hydrate (NZ$4.09/GJ and NZ$3.47/GJ respectively).

   The economic benefits remain substantial even when the LNG is priced according to the Guandong formula with IRR's of 21.5% and 17.4% for the two scenarios, indicating hydrate production can withstand significant downward pressure on regional LNG prices under base case assumptions.

2. Hydrates are unlikely to be competitive with domestic natural gas. Both 10 PJ scenarios have negative internal rates of return as the cost of production of hydrate will most probably be significantly more than that of natural gas. However, an acceptable rate of return might be attained if part of the output from an export scale hydrate development was directed to exports to capitalise on the relatively high LNG-related prices, as illustrated in the sensitivities section of Table 5.8 where gas value is set at domestic levels.

   More importantly, however, the 10 PJ case provides an indication of the risk premium that may need to be underwritten in the initial stages of the project, whilst full development continues. This is more fully covered in the analysis of the composite or staged development scenario later in this chapter.

3. Table 5.8 also illustrates the sensitivity of the economic rate of return to changes in some of the base case assumptions used in the analysis. Even when taking large variations in the principal inputs of project costs, oil price and exchange rate, the internal rate of return remains above 5% for the scenarios predicated on LNG prices, indicating that there is significant margin in the project to absorb adverse shifts in the conditions underlying development.

4. At an oil price of US$ 20 per barrel and correspondingly low LNG prices, the internal rate of return remains at or in excess of 10% for both the 150 and 300 PJ scenarios under both LNG pricing formulae. Given recent history, it is improbable that a long term oil price below this level would be sustained, suggesting that a hydrate project replacing LNG imports will provide economic benefits under most oil and LNG pricing outlooks, provided the base case assumptions for project costs remain sound.

5. Similarly, internal rates of return will remain above 10% if the exchange rate were to be increased to 0.85, slightly above the highest rate experienced in the last 20 years, which effectively reduces the benefit obtained from replacing US dollar

denominated LNG. A combination of this high exchange rate and US$ 20/bbl. oil would reduce IRR's to 6.7% and 10.1% for the 300 and 150 PJ scenarios respectively, or 4.2% and 7.9% using the Guandong formula. However, this combination is counter-intuitive as a weak US dollar is generally associated with higher prices for US dollar denominated commodities such as oil.

6. Doubling the project costs will reduce economic IRR's to 16.5% and 18.5% (8.0% and 10.2% using the Guandong formula) for the 300 and 150 PJ scenarios, indicating the project is robust relative to the assumptions on capital and operating costs. However, whilst they are considered conservatively high at this time, the hydrate costs are based on unproven technology and in the absence of any commercial development that would allow better calibration of these cost estimates. At doubled project costs, the 5% economic IRR threshold is reached when the oil price is reduced to US$22.60/bbl. for the 300 PJ scenario and US$17.10/bbl. for the 150 PJ scenario (US$39.90/bbl. and US$24.60/bbl. using the Guandong formula), suggesting the hydrate development will be economically attractive under most cost and oil price outlooks. It also emphasises the importance of accelerating investigations into hydrate technology development to reduce uncertainties regarding project costs. The impact of oil prices on hydrate project economics is discussed in more detail in the next section.

7. In the 10 PJ scenarios, the 5% economic threshold is met only with domestic gas prices at NZ$18.50/GJ and NZ$4.80/GJ for the 10 PJ/C and 10 PJ/S scenarios. These would have to be nearly doubled to result in a commercial level IRR of 15%, indicating it is highly unlikely that hydrates would compete with domestic gas resources. Only the 10 PJ/S scenario would be competitive with imported LNG under the BAU criteria, even with doubled project costs, but this does not represent a long term commercial case.

Understanding the impact of gas hydrates on regional LNG prices

Whilst oil price is the primary energy price variable used in this analysis, it is the LNG price derived from it that directly influences the hydrate project's economic performance.

The relationship between LNG price and project IRR is independent of the two LNG price formulae discussed in Section 5.3.2 and is shown in Figure 5.5 for the base case and also with project costs escalated 100% to reflect the general uncertainty surrounding project costs.

Even with double the base case costs, the hydrate project will deliver a 5% IRR at an LNG price of less than NZ$ 8.00/GJ CIF, with the requisite LNG price ranging from NZ$1.60/GJ for the 150 PJ scenario to NZ$7.30/GJ for the 300

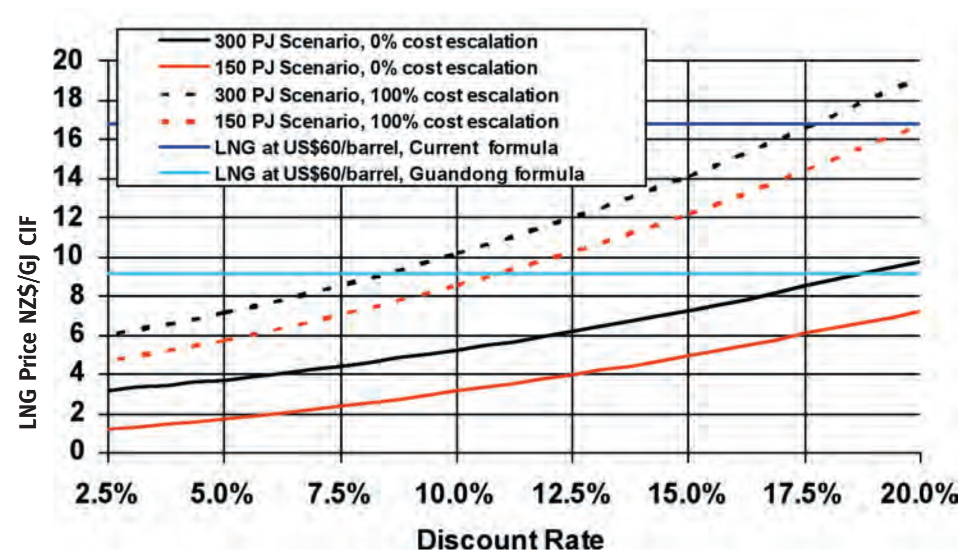

Figure 5.5: The linkage between crude oil prices and hydrate project IRR under the two LNG pricing formulae

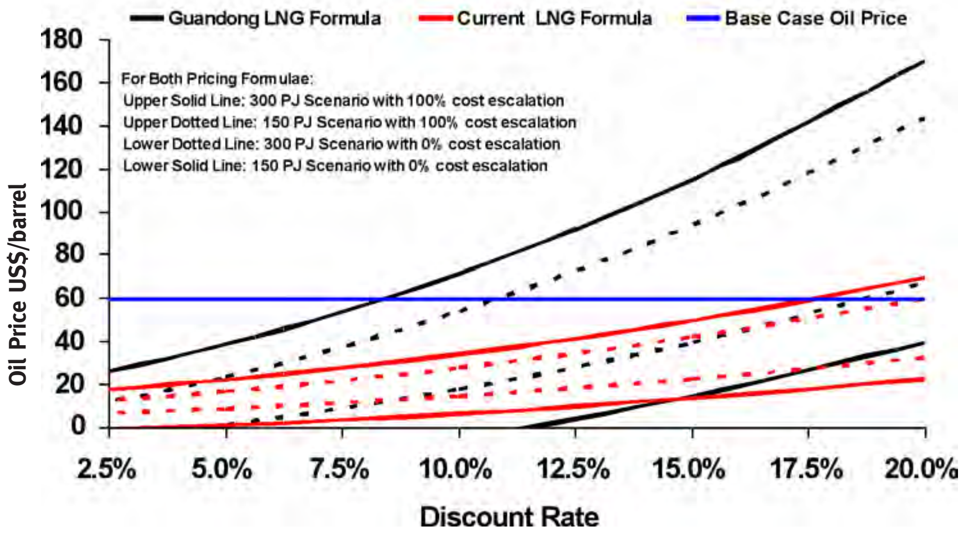

Figure 5.6 above illustrates the linkage between oil price and project internal rates of return

PJ scenario with costs escalated 100%. These LNG prices are below those determined by both the current and Guandong price formulae (shown in Table 5.6) at NZ$16.77/GJ and NZ$9.10/GJ at the base case oil price of US$ 60/bbl., again reinforcing the proposition that hydrates derived natural gas is likely to be the lesser cost option compared to a reliance on LNG as a 'backstop' fuel for New Zealand.

Figure 5.5 shows the linkage between crude oil prices and hydrate project IRR under the two LNG pricing formulae, representing high and low relativities between LNG and oil prices. General conclusions from this analysis that attest to the economic potential of gas hydrates include:

1. When LNG price is the basis for gas hydrate value, an economic criterion of 5% IRR is met in all base case project scenarios, including the doubling of project costs, both high and low LNG price relativities with oil and oil prices as low as US$40/bbl., significantly below the official outlook of US$60/bbl.
2. A commercial criterion of 15% IRR will be met at an oil price of US$60/bbl. in all scenarios with the exception of a combination of low LNG prices relative to oil (when applying the Guandong formula) and escalated project costs, providing opportunities for hydrate producers to undercut LNG priced at current relativities with crude oil. This becomes more pronounced at oil prices above US$60/bbl. and vice versa.

Benefits of Accelerating Hydrate Development

This section is intended to evaluate the impact of bringing forward the date of first hydrate production from 2040 through government assistance, including direct investment during the exploration and appraisal stages of the hydrate resource, assistance towards technology assessment, tax incentives and/or other policy and permitting considerations, under two cases:

- By ten years to 2030;
- By twenty years to 2020, the latter being the very earliest hydrate technology could realistically be brought on-stream under ideal circumstances. While assessment costs in this 2020 start up case have been modelled to be incurred over a five year period to meet the accelerated implementation schedule, this has been found to have a virtually negligible impact on the analysis.

The output principally affected by the different start up dates will be the project economic net present value due to the effect of the time value of money. Figures 5.7 and 5.8 illustrate the relative discounted costs of supplying gas to the New Zealand market over the period 2009 to 2075 for the 300 PJ scenario, allowing for the export of 150 PJ and the retention of the same amount for the domestic market.

The broken black line in Figures 5.7 and 5.8 is the difference in discounted annual

National Gas Supply: Total Discounted Costs
150 PJ Domestic Demand, %5 Discount Rate

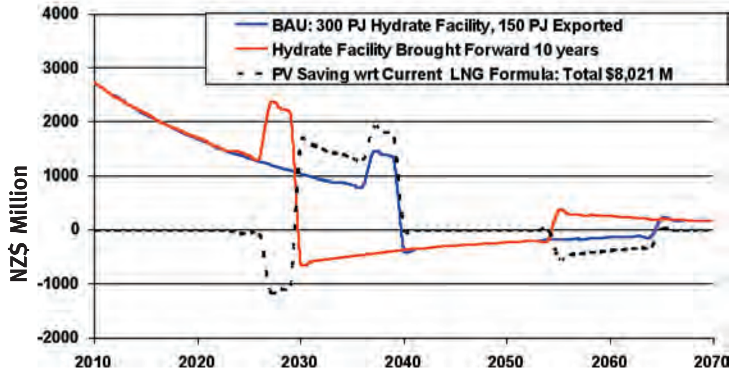

Figure 5.7: Economic impact of accelerating project by 10 years

National Gas Supply: Total Discounted Costs
150 PJ Domestic Demand, %5 Discount Rate

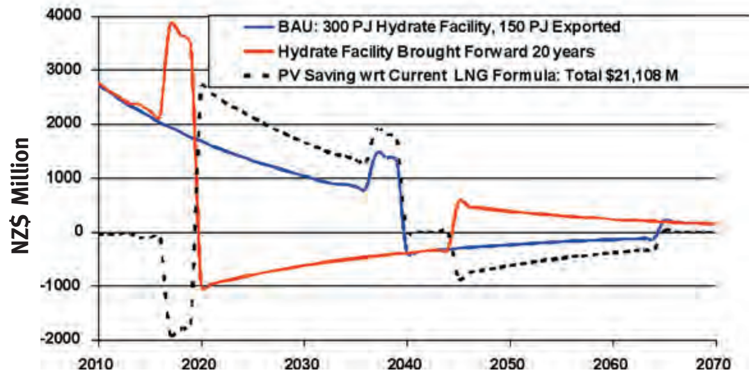

Figure 5.8: Economic impact of accelerating project by 20 years

cost (negative being more costly) between the 'business-as-usual' and the 'accelerated development' cases. The sum of these annual costs (or the area under the broken line) is the reduction in total present cost of gas supply by bringing the project forward. The savings have been estimated at NZD$21,012 million for the 2020 start up case and NZD$7,983 million for 2030 start up over the 67 year period.

General conclusions that be drawn from this analysis suggest that there is a significant potential to reduce the long term cost of the supplying gas to the New Zealand market by accelerating hydrates development:

1. Under base case assumptions, the net present cost of gas supply by hydrate could be up to about 25% lower over a 65+ year period if the start of hydrate production was brought forward from 2040 to 2020. This saving could be increased further if LNG exports were included in the hydrate development.
2. This same benefit will, however, not apply when displacing low cost indigenous natural gas, as illustrated in the two 10 PJ scenarios. As shown previously, the BAU internal rate of return, and hence net present value, for this scenario is negative and consequently, bringing forward the start of hydrate production will increase the net present cost of gas rather than reduce it.
3. The marginal hydrate exported will be similar to those used in the economic analysis as the methane has been valued against international LNG prices and project costs effectively will be the same, although not necessarily all born by the project developer. A pre-tax internal rate of return of 13% may not be sufficient for developers.

Staged Hydrate Development Scenario

A composite scenario, based on the staged development of a 10 PJ pa 'proving project' acting as a precursor to, and designed to be integrated into a future commercial 150 PJ or 300 PJ development 10 years after first production, has been included to better reflect a probable development pathway. It is envisaged that investment in a preceding 'proof-of-concept' project provides scope for the development of technology experience and also a mechanism to more effectively manage the risks associated with full commercial production.

Key characteristics of this composite scenario include:

- The 10 PJ/S scenario is an alternative development scenario to illustrate the cash flow implications of such a development pathway;
- Production is expanded to 300 PJ eight years after first production, providing time for technology and market development;
- Exported methane is valued as in the 300 PJ scenario. Methane sold into the domestic market is valued against the replacement of indigenous gas until 2015 and then ramped up to parity with imported LNG prices in 2020 and held constant thereafter.

A comparison of the costs of production and derived internal rates of return for each of the scenarios is provided in Table 5.9 below while cash flow and methane value profiles for the composite scenario are shown in Figure 5.9. There are only small differences in the internal rates of return for the composite scenario with the 10 PJ/S initial development and the 300 PJ scenario.

The economic benefits of the composite scenario are dominated by the performance of the second phase of the project whose income and expenditure dwarfs those of the 10 PJ proving development.

If the investment schedule follows that of the 10 PJ/C scenario, the difference in IRR between the composite and 300 PJ scenarios widens. In this case the capital cost of the proving project is 15% of the total and the disproportionately low income during this initial project phase will reduce project rates of return. However, they remain above the economic benchmark.

The staged development will reduce technology risk and market risk as output from the 10 PJ proving phase should be relatively easy to balance with market demand. Larger developments, as illustrated in the 150 PJ scenario, may offer greater economic benefits but face a more challenging and protracted effort to sell their full capacity on the domestic market. Inclusion of export capacity in the latter 300 PJ phase will provide flexibility and anchor demand during the ramp up of the domestic market.

Scenario	Composite 10 PJ/C		Composite 10 PJ/S		300 PJ	
Cost of Production NZ$/GJ	$3.67		$3.60		$3.47	
LNG CIF (Import) Price in NZ$/GJ	Guandong	Current	Guandong	Current	Guandong	Current
	$11.41	$19.08	$11.41	$19.08	$11.41	$19.08
LNG FOB (Export) Price in NZ$/GJ	Guandong	Current	Guandong	Current	Guandong	Current
	$6.13	$13.80	$6.13	$13.80	$6.13	$13.80
IRR under Base Case Assumptions	15.4%	23.2%	16.3%	25.0%	17.4%	26.9%

Table 5.9: Internal Rates of Return for Composite and 300 PJ Scenarios

- All 3 scenarios have an ultimate capacity of 300 PJ: 150 PJ sent into the domestic market (CIF price) and 150 PJ into exports (FOB price)

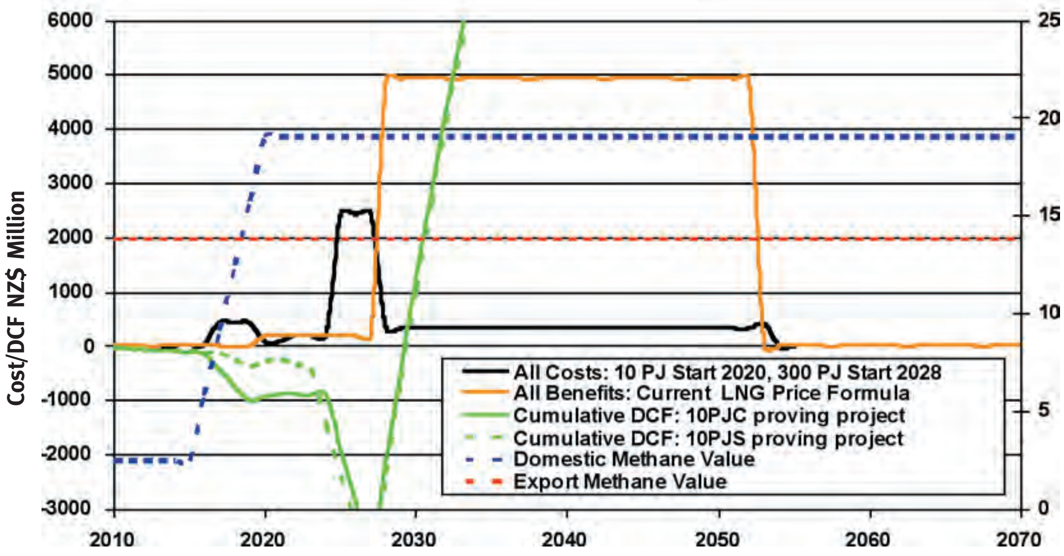

Figure 5.9: Discounted Cashflows for the Composite (staged) Hydrate Development: 10 PJ/C and 300 PJ, 5% discount rate

5.2.3 KEY FINDINGS

Gas hydrates offer a real opportunity to make a significant contribution to New Zealand's longer term energy requirements with large deposits identified close to the North Island coast and within relatively easy access of existing natural gas infrastructure.

Based on the best information currently available, this analysis indicates that the use of hydrates potentially will bring economic benefits to New Zealand and these can be increased by policy directed at accelerating their development.

1. Gas hydrates can be produced at significantly lower costs than imported LNG, resulting in economic internal rates of return significantly higher than government guidelines[8] for hydrate developments replacing potential LNG imports. This provides a significant opportunity for hydrates if insufficient reserves of indigenous natural gas are found to meet market requirements. However, it is improbable that hydrates would be competitive with natural gas if sufficient indigenous reserves of gas were to be discovered because of the greater complexity and cost of hydrate production.
2. Whilst the use of imported LNG as a shadow economic price might overstate the value of gas hydrates in the domestic energy market, this analysis demonstrates that gas hydrates present a better alternative to LNG should be latter be a commercially viable backstop for dwindling indigenous natural gas reserves.
3. Technology for hydrates extraction and processing is in its infancy, with no development having been commercialised as yet, placing a high level of uncertainty on the cost estimates used in this analysis. Whilst there is a significant margin between hydrate project economic IRRs and government guidelines[9] based on these estimates, the hydrates IRRs will diminish should these costs increase, the outlook for oil prices decrease, or LNG prices become depressed through competition with gas hydrates (should the uptake of hydrate methane become widespread). Increasing the research effort to understand and prove hydrate technology will reduce this uncertainty, minimise investment risk and help bring forward commercialisation of hydrate resources.
4. Accelerating the development of hydrates resources as an alternative to imported LNG will significantly reduce the long term economic cost of supplying gas to the New Zealand market. It is important that policy settings are put in place to encourage early investment in New Zealand's hydrate resources otherwise international investors in this technology will preferentially concentrate on other hydrate resources with access to larger and more diverse energy markets.

8 Section 10.3.3 of New Zealand Energy Strategy to 2050, October 2007

9 ibid

5. Export of hydrate methane as LNG is technically feasible and is potentially capable of reducing market risk for a large scale development by diversifying out of the fragmented New Zealand gas market, and providing an anchor investment through long term export contracts. However, the economic and financial benefits of exports will be lower than competing with LNG in the domestic gas market and will be more sensitive to project costs and the outlook for oil and LNG prices.
6. A staged hydrate project development with a small proving project preceding the main development appears to be the most optimal gas hydrates development pathway to reduce project risk and help understanding of technical and marketing issues prior to the principal investment in the project. Whilst the second, larger phase will dictate overall project economics and will be attractive if competing against LNG, the proving phase will not (and should not be intended to) be commercially self-supporting. Government policies directed at supporting investment during the proving phase will greatly facilitate the implementation of any subsequent large scale commercial development.

6. AN INFORMATION MANAGEMENT FRAMEWORK FOR GAS HYDRATES

6.1 Introduction

As can be seen from the earlier sections of the report, a strong and growing interest in gas hydrates as a potential unconventional energy resource is beginning to draw gas hydrates research from its highly technical niches and the literature into mainstream. As a result, there is an increasing demand for access to technical and resource appraisal information, as well as more public domain science information, to inform policy makers and other interested parties on the issues of developing gas hydrates as an energy resource.

In a conventional resource development pathway, this information is typically available either through science activity funded by government or as part of the work programme requirements associated with prospecting and exploration permits to build the case for exploration drilling and eventual development of discoveries. However, this information and data is generally exclusive to the permit holder and not usually available until the expiration of the permit.

From a research perspective, the key sources of New Zealand gas hydrates information are those entities which have been involved in relevant research in alliance with their overseas collaborators: Crown Research Institutes (GNS Science (geological and geophysical) and NIWA (geological, geophysical, biological, chemical and oceanographic)); and to a lesser degree, Otago (geological and geophysical) and Canterbury Universities (chemical and process engineering).

This information is predominantly focused on geological and geophysical data, with interpretation at a regional or field level. However, access to the information held by the research and academic institutions may, unless published, be impeded due to:

- Relevant information being held under embargo or access restrictions pending publication, due to the collaborative research arrangements under which the information was collected;
- Research information not being available to external parties due to commercial sensitivities.

More importantly, however, the objectives of scientific and academic research are not directly commercial, and utilisation of both high cost data and resulting knowledge arising from research by the wider community may be impacted due to:

- The often untimely publication of research in highly technical and/or niche publications, not well known or accessible outside narrow fields within the research community;
- Relevant information may have historically been peripheral to the focus of many of the original publications, and thus, not well known outside specialist fields.

Furthermore, the very design of research programmes will generally be quite different from commercial scientific effort, especially when the priorities of New Zealand participants have to be integrated with those of overseas collaborators who are relied on for specialised facilities such as vessels or particular analytical capabilities.

At the current pre-commercial or "pioneering" stage of evaluation and technology discovery pertaining to marine gas hydrates, no work has been or is being conducted under exploration or prospecting permits. The only data available is either historic petroleum exploration seismic survey results or geophysical and oceanographic data collected under public sector research programmes. To effectively integrate data and knowledge from these two domains, both the open-file system administered by Crown Minerals for the petroleum industry, and the scientific systems within New Zealand and internationally, need to be readily accessible.

The issue that thus arises is that, too often, public policy development needs to be considered in advance of the permit regime and in the absence of a coherent science information knowledge base.

An example of this type of issue is the current permitting moratorium on the hydrates areas of the North Island of New Zealand. However, this is only part of the equation and there needs also to be a broader more encompassing approach to consolidating and centralising the other types of data and relevant information required to support the development of robust and effective allocation arrangements to cover development efforts for 'frontier opportunities' such as methane hydrates.

This chapter explores in more depth some of these issues, including the case for establishing a centralised repository for New Zealand gas hydrates information, as well as the wider issue of adapting the New Zealand permit regime to meet the precommercial nature of the hydrates resources.

6.2 New Zealand Gas Hydrates Information Repository

To complement MED initiatives to promote New Zealand petroleum and mineral resource opportunities (e.g. the Seismic Data Acquisition Programme) and potentially, future MED gas hydrate initiatives, CAENZ was asked to investigate the establishment of a New Zealand gas hydrates information repository.

This task encompassed:

- A review of international gas hydrates repositories;
- Assessment of repository software applications and operating platforms;
- Consideration of MED's functional requirements, existing information management infrastructure and software integration requirements;
- Assessment of a number of applicable information repository software applications;
- Discussions with GNS Science and NIWA regarding access arrangements to their respective information repositories.

Whilst recognising that both GNS Science and NIWA maintain individual gas hydrates databases, it was hoped that this repository could act as a centralised clearing house for relevant research, data and other information relevant to New Zealand gas hydrate resources. However, the results of the investigation identified a number of key issues that would affect the functionality and content of such a facility.

Intellectual Property Ownership

Intellectual property ownership was found to be a key determinant of content for the repository. For example, when a research paper is published, the intellectual property associated with that publication is generally transferred from the author(s) to the publisher, unless alternative arrangements are made. This means that in many instances, published papers are unlikely to be deposited in a repository, thus defeating its purpose.

International collaborations involving New Zealand researchers also impose their own particular ownership and access arrangements on publications and data, which may restrict their inclusion in the hydrates repository.

Additionally, data acquired by New Zealand research institutes through commercial arrangements may also be subject to access restrictions. The implications for inclusion of data gathered and collated through the current permit arrangements can be problematic, and limitations are likely to be imposed.

Internationally, many of the information repositories reviewed by the study team have bypassed the IP ownership issue by tending predominantly to host student theses, publications from their own presses, unpublished papers or pre-publication versions of published papers and conference proceedings (i.e. the University of British Columbia's circle repository which hosts the Proceedings from the 2008 International Conference on Gas Hydrates).

However, hosting 'meta-data' (bibliographical and publication data) and abstracts offers an intermediate method of building content for the repository.

Replication

Despite the silos of information held by the various research institutions, it is important to ensure that the repository does not replicate these databases.

It is thus suggested that in order for any future repository to fulfil the objectives of a centralised clearing house, suitable access arrangements be negotiated with the CRI's.

Technical Issues

A number of technical risk factors were identified in the course of the review that will need to be addressed. These include:

- The need (if any) for any selected repository application to meet New Zealand e-Government web standards[1] and MED/ Crown Minerals Digital Data Provision standards[2];
- While the Government Shared Workspace[3] may provide a relatively cheap and secure platform for deployment of a repository application, questions remain regarding access by non-government employees and external parties. [We note that as of February 2009, management of the Government Shared Network or GSN has being transferred from the State Services Commission to Government Technologies Services, as part of a managed exit process of government agencies from this network. Its long term future remains to be seen];
- The need for a Concept Plan for a Methane Hydrates Repository

Based on a close analysis of the available options, an outline concept plan has been developed for a function to meet MED's objectives for the gas hydrates resource. It is envisaged that this would involve two stages:

Stage 1:

- Full papers and publications will be hosted where MED is either the sponsor or client, or has secured a release from the owners of the intellectual property;
- Meta-data (publication and bibliographic information and abstract) and links will be provided to all other papers and publications that it has not secured a release for;

1 http://www.e.govt.nz/standards/web-guidelines/
2 http://www.crownminerals.govt.nz/cms/pdf-library/petroleum-legislation-1/petroleum-digital-data-submission-standards.pdf
3 http://www.e.govt.nz/services/workspace

Stage 2:

- Integration with MED Minerals and Petroleum Databases;
- Links to New Zealand Crown Research Institutes' information repositories (to be negotiated);
- Links to other relevant information repositories (to be identified and negotiated)

We anticipate that the project, as above, could commence immediately as a pilot programme on the next intermediate stage to finalise access requirements and protocols for access and distribution of information gathered in the course of any ongoing hydrate development work. Doing so will go a long way to establish the business case for ongoing investment in such a facility.

6.3 Information from the New Zealand Petroleum and Minerals Permitting Regime

Under the Crown Minerals Act 1991, the government holds title to undiscovered oil and gas, and allocates exploration and development rights to spatially-defined permits on an exclusive basis for specified terms conditional on agreed investment (work) programmes.

If New Zealand is to be at the forefront of the gas hydrates industry, then the current permitting regime will need to be adapted to dovetail with the timetable within which the main lines of research can be expected to progress to a fully commercial proposition.

Under this regime, Crown Minerals issues three types of permits to prospect, explore or mine petroleum resources, as summarised in Table 6.1.

In essence, the permitting regime within the Crown Minerals Act 1991 establishes a pathway to gain an exclusive right to exploit a particular discovery.

	Prospecting Permit	Exploration Permit	Mining permit
Purpose	Reconnaissance and general investigation of an area	Identification of deposits and feasibility studies	Development, extraction and production of discoveries
Activities	Acquisition of geological and geophysical data	As for prospecting, also surveying, exploration and appraisal drilling, testing of discoveries	Mining, extraction and production activities
Allocation	Non-competitive	Priority in time Competitive – Blocks Offer	Subsequent to previous activities, requires acceptance by Crown Minerals of an appropriate work programme for the development and mining of a discovery
Rights	Non-exclusive No subsequent rights	Exclusive, subsequent rights to apply for a mining permit	Exclusive
Duration	Up to 1 year	Initially for up to 5 years Renewal for 5 years Appraisal extension of up to 4 years	Up to 40 years, related to size of discovery and rate of production

Table 6.1: Types of Petroleum Permits[4]

As a pre-commercial resource opportunity, methane hydrates will require explicit separation, perhaps through the mechanism of stratified title / strata permits, in order to prevent the stranding or 'sterilisation' of the hydrate resource. Under the current permitting regime, it is conceivable that an exploration permit granted for conventional petroleum resources may prevent commercial development of a co-associated / co-mingled hydrates discovery for up to 14 years.

It is also conceivable that without separation or exclusion of hydrates from conventional petroleum permits under the current regime, that the advent of new hydrates extraction and production technologies during the term of the permit may provide the permit holder with a windfall opportunity and the New Zealand Government with a potential loss of royalty revenue.

As a pre-commercial opportunity, without explicit recognition of methane hydrates under the existing permitting regime, it is likely that the longer term horizon for commercialisation of hydrates relative to the shorter term (i.e. the one or two year time frames for petroleum) may create a crossover with potential for competing interests over the same acreage. Appropriate mechanisms will need to be developed to deal with potentially competing timeframes.

We note that NZ has faced a similar situation of competing interests in respect of coal bed methane. In this example, the industry arrived on the scene before the science had actually been completed. A permitting regime was hastily implemented without adequate knowledge of the nature of the resource or the way the resource opportunity needed to be developed. Recent anecdotal evidence suggests that the current permitting arrangements for coal bed methane remain clumsy and not particularly comprehensive.

4 http://www.crownminerals.govt.nz/cms/petroleum/permits-content/permits-how-do-i-apply-faqs-1/what-are-the-different-types-of-permits

We suggest that a better, more targeted policy and legislative framework that provides for the management with, rather than of, risk needs to be implemented; rather than simple adoption of policies based on the 'precautionary principal'. Such a regime will also need to be cognisant that it is impossible to foresee all problems or even the development timeline, at the commencement of a pioneering opportunity.

The absence of a sufficiently clear and robust policy and legislative framework for pioneering resource opportunities like methane hydrates presents a significant risk to the Crown. As discussed previously, at the very worse case, an early decision to allocate acreage within the known hydrate theatres may sterilise gas hydrates in the future.

Any permitting regime needs also to take into account the reality that it is not always possible to adequately forsee future problems or even development timeframes. This applies in particular to hydrates where the pace of technology development, especially key front end geo-technical and engineering issues, may well be ill defined at the commencement of the exploration phase. An example relevant to the New Zealand hydrate resource will be the ability of a potential operator to get over the pressure/temperature barriers for hydrate recovery over such huge dispersed volumes.

For these reasons, we argue that the permitting regime and related petroleum exploration policies will require a different approach than normal policy settings. We suggest that the way forward should also involve a competition of ideas, not technology or science push; in other words, simply aiming for a research corridor as an outcome is not a sufficient reason for permitting decisions. This study has demonstrated that the commercial development of methane hydrates is a serious proposition. Thus, time diverted to demonstration, scale-up and rollout, unless the resolution of technical risk factors is shown to dominate, is simply an opportunity cost to the nation. We argue instead that the most optimal development path is to proceed on the basis that technologies are, or will be, available during the development timeframe of the project.

We are fortunate that appropriate technologies do exist, and are to be found in the process industries. But the standard time lines allowed for under existing petroleum and mineral regimes are too short for the emergence (commercialisation) of pioneer frontier opportunities. Policy direction thus needs to ensure that the longer timeframes required for hydrates exploitation is sufficiently clear, that development objectives are well understood and timescales agreed. Moreover, the dimensions of that ambition will also need to be defined at some early point.

Whilst getting the right allocation regime in place is a crucial part of going forward, without a comprehensive or coherent legal framework for development there is also likely to be considerable additional uncertainties that would impact on virtually every aspect of a commercial-scale project. Experience in the US on carbon capture and sequestration (CCS) (e.g. Hart 2009) suggests that issues surrounding long-term liabilities have created significant barriers to almost all projects, even where projects are acknowledged as posing little or no risk.

With respect to hydrates development these risks centre on the lack of a clearly delineated Oceans Policy in New Zealand and the lack of certainty around jurisdiction and environmental effects, including:

- Performance requirements under exploration regimes,
- Access, safety, and environmental effects,
- Consents for exploration, development, operation and closure of any hydrate site,
- Long term monitoring, remediation and residual financial responsibility for hydrate sites,
- Liabilities for emissions control, flaring, commingled resources, and potential competing use rights
- Treatment and accounting for gas hydrates under any future carbon mitigation regime, etc.

The commercial development of frontier opportunities will inevitably challenge conventional resource law and governance. Again US experience suggest that liability issues such as those enumerated above proved difficult to resolve because lead research organisations would not ordinarily be expected to manage such issues and project proponents lacked the necessary experience or financial capacity to appropriately manage the risk.

In its previous studies on Oceans Policy (CAE 2001, 2003, 2005, 2006), The Centre suggested that in order for oceans policy to be more supportive of frontier activity there should be a greater tolerance of risk commensurate with the uncertainty prevalent in activities of this type and posed by lack of information.

Typically, frontier activities such as hydrate research, are characterised by insufficient data in the early stages of investigation to support normal business appraisals; and even more critically, a lack of knowledge regarding potential consequences of unanticipated events. Access to such knowledge will be essential to all stakeholders including those relating to health and safety, environmental management, exploration and finally through to commercial operations. These stakeholders include the research community, government, investors, lenders, service providers, regulatory agencies and insurers.

Again, what comes clear from this study is that the key during this intermediate stage is that there are sufficiently robust processes in place to ensure we have more cost-effective application of knowledge allowing for proactive intervention by government when appropriate. Our observation in researching the requirements for a possible gas hydrate information repository is that under current science funding regimes, much of the critical data is held under embargo whilst providers retain the knowledge to meet their own commercial imperatives, rather than providing for knowledge to be shared.

We have previously argued for a separate oceans agency having as one of its functions the allocation and administration of property rights including information management and brokerage. Whilst this may not be possible in the current environment, it is essential that New Zealand break out of the trap of exclusive rights; and instead, overlay an objective, durable and transparent information management regime that balances the need to incentives pioneering activity whilst also ensuring sufficient competition to maximise the opportunity value to New Zealand.

One way forward is through a procurement-type route as outlined in the following section. A large and robust data base containing multiple data points and engineering information collected from actual projects worldwide over a broad range of geological and other conditions (subsurface geophysics, seismic, wave, climatic, etc) will be necessary for developing more accurate metrics for a engineering assessment of a New Zealand project. This could provide the first contriution towards proposed Gas Hydrates Information Repository.

6.4 Providing for Commercial Information Requirements

The information requirements for commercial decision taking are broad, multi-faceted and generally highly interactive. There is also a need for flexibility in order to respond to changing circumstances, government decisions or new commercial imperatives. The legislative and policy frameworks that need to apply to pioneering or frontier activity are the extreme example of operating with uncertainty. Rather than a closed science investigative approach, there needs to be a closer alignment between science investment and a conventional engineering stage gate approach for the assessment of project risk and evaluation of project investment.

Ultimately, the development pathway chosen will determine the research requirements. A general framework for decision making needs to be adopted that anticipates the way new information obtained at each stage of the investigation feeds into the overall project evaluation, i.e. a stage-gate approach. Explicit treatment of “real options” created and/or destroyed by key decisions along the project path should also be included. Such an approach requires expert determination and review of whether the information assembled is adequate for the stage of the project and whether all realistic options have been considered.

Access to such expertise is not likely unless opportunity is taken to either participate in international initiatives (such as the Gulf of Mexico) or alternately is procured via commissioned studies utilising acknowledged international expertise and know how. So doing ensures that the information required to enable evaluation is available at each given point of time as required. Open access to all project information, documentation and reports is particularly vital in the early stages of project definition to ensure that assumptions used are reasonable and robust, and that all risks have been properly identified and acknowledged.

Development of a comprehensive hydrates information repository is essential for future investigation and evaluation of the hydrates opportunity. It is important for New Zealand to invest in information and knowledge development in this area. Through bringing this investment inside the overall investigative framework, the knowledge created can be retained as an exclusive property right by government but the right to use can be made contestable as part of any considerations under a future permitting or development rights allocation.

In the intermediate pre-competitive investigative stages, prior to the "doing" of the project, access to the repository will facilitate the early resolution of development hurdles and other impediments. Adopting this approach will require that work programme be undertaken at arm's length to existing regulatory agencies or commercial interests.

Moving forward requires that we assess all opportunities available to us. In evaluating a resource opportunity, there are several questions that need to be addressed. A stage gate process that allows full comparison of the different options is recommended. The decision framework through the pioneering stage of gas hydrate development requires the following information (not intended as exhaustive) to be established:

- The extent and characteristics of the resource;
- The feasibility and environmental impacts of resource recovery;
- The technical feasibility of production on a commercial scale;
- The commercial feasibility of production and utilisation;
- The social and environmental acceptability of the selected development scenario;
- The availability of the necessary infrastructure requirements including a skilled workforce;
- The factors involved in implementation of any option and initial strategies for implementation;
- Compatibility with national policy objectives.

7. PRELIMINARY RESULTS

7.1 The Way Forward

This study indicates that New Zealand can benefit substantially from a proactive strategy directed at pioneering large-scale commercial development of marine gas hydrate resources.

Development of the hydrate resource, however, will not be an easy road. What we have learned from this study is that the current state of scientific and engineering knowledge is not yet a sufficient basis for the scale of investment involved. Major investment to develop a more comprehensive scientific understanding of the gas hydrate deposits, as well as considerable advancement in engineering geology (marine geo-technical) and production engineering practice will be required. Until the feasibility of development has been proven, this R&D investment is characterised by a significant level of risk.

It is the view of the study team that the potential benefits of marine gas hydrate development in New Zealand at the earliest practical stage justify a concerted, strategic initiative to that end. Deployment of the necessary resources for such a track will be expensive and risky. Government needs to consider the capacity of potential sources of investment capital and technical expertise to leverage its own interests in the opportunity.

Under current policies, a marine gas hydrate industry could be expected to arise from a private sector initiative governed by the Crown Minerals Act (analogies include the investigations into seabed massive sulphide mineral deposits along the Kermadec arc, and into coal seam gas in several provinces). We consider it unlikely that, at the present state of knowledge and capital availability, a compelling commercial case could be made for development of the resource solely within the private sector when the capital and technical requirements and risks are fully taken into account.

It is thus recommended that Government should look to develop and implement a strategic programme to bring forward the commercial development of the gas hydrate resource so as to ensure that the resource is unlocked and the national benefits are fully realised. Whilst gas hydrate appears to fall within the intended scope of the Minerals Programme for Petroleum (i.e. gas hydrate is a class of petroleum), a high level of discretion will be required in relation to methods of permit allocation and administration to ensure an optimal outcome. Currently, the main prospective area is closed to petroleum exploration permit applications, maintaining the opportunity for Government to implement a proactive, and strategic programme.

In addition to conventional regulatory roles, Government should evaluate the extent and nature of gaps in the business case for gas hydrates development (e.g. insufficient risk-tolerant capital, and weaknesses in the supply chain) and develop strategies to ensure that these are effectively bridged.

Technical development will need to embrace novel and new operating environments. Risk components include the likelihood of technological obsolescence during the course of the project, interactions between a wide range of stakeholders, competitive factors, and regulatory uncertainty. Vital challenges in establishing a commercial proposition include:

- Achieving and maintaining the technical capacity to develop the technology and support ongoing resource evaluation;
- Adequate financing for multi-stage investigation and development;
- Commitment to maintaining long term working relationships between key stakeholders; and
- Appropriate incentives to ensure a bankable project eventuates.

An important additional consideration will be the capacity to see the development process through to commercial completion (abandonment would be very expensive and could well impact adversely on New Zealand's international reputation as an exploration play) and ensuring the institutional capacity to cut across competing interests so as to ensure an optimal outcome for the country.

Determination of these factors goes beyond just administration of the Crown Minerals regime, and will require a development framework that embraces risk as an opportunity and is capable of managing the trade-offs between public expectations of certainty and the fiscal and technical realities of the development pathway.

Current institutions in the New Zealand economy fall short of the full set of ingredients required to unlock the potential of our marine energy resource endowment. Besides its established regulatory roles, government must address the specific shortcomings. It is thus the study team's view that some form of special purpose vehicle may well offer a more focused, cost effective means of delivering the desired research and opportunity assessments; as well as providing a more equitable risk sharing arrangement to manage the complexities that will inevitably arise.

Government has numerous options as to how the technology, engineering and capital might be brought to bear to deliver the required research and development effort. It would certainly be most desirable to incorporate a significant private sector element, to the extent that the opportunity is attractive to financially and technically qualified parties. Clearly, whatever structure is chosen, the goal should be to achieve a greater capability and performance than might otherwise be the case from a 'business-as-usual" (reactive) approach.

Major factors that need to be taken into account include separation of regulatory from commercial interests, governance and control, capital and security of any assets, risks and liabilities created, ownership and treatment of intellectual property, compliance with statuary and regulatory conditions and ultimately, the national interest. The proposed special-purpose vehicle should be deliberately transient in nature: designed to either evolve into a production-oriented business following the proving of commercial development, or to be wound up if this step did not eventuate.

Such a body can be provided through legislation with the required independence and legal standing to take on those risk elements that might otherwise deter sufficient private sector participation in a resolute, coherent and necessarily extensive resource evaluation programme. This entity would thus become New Zealand's counterpart to foreign government agencies and national oil companies for technology exchange and other commercial arrangements, and could form joint ventures or other appropriate arrangements with sources of equity capital at the different development stages.

A possible model is that of the former Liquid Fuels Trust Board that was established in the 1970s to promote and advance activities that reduced this country's reliance on imported fuels. Another model to consider would be a state owned company, which could operate in a commercial manner to bring together the technology, and capital required, directly and through contractual arrangements, joint ventures etc as appropriate. Countries such as India, China, and South Korea, through their national oil companies, are applying such mechanisms to the development of their gas hydrate resource opportunities.

However, the way forward outlined here represents, in the study team's opinion, a unique approach to the development of the New Zealand gas hydrates resource endowment, that is intended to maximise the national benefit while recognising the constraints that such a development would face in New Zealand; including limited research funding, indigenous E&P sector size and participants, energy end-use factors, etc.

We have not, however, discounted the successes achieved through the RFP process of the US DoE model, or the approaches adopted by other national programmes. We suggest a more in-depth evaluation of these different approaches be undertaken to identify applicable opportunities for New Zealand.

7.2 Energy and Resources and Economic Policy Context

If the objective is to unlock New Zealand energy and resource opportunities, it is essential that this country have realistic scenarios concerning all potential sources of petroleum and other thermal fuel supply.

New Zealand is a resource rich country, a reality that has often been neglected and overlooked because planning has been driven by short term horizons and a prevailing view that energy supply in this country is there only to meet domestic demand. The small size of New Zealand's energy market inevitably leads to intermittent supply constraints, inflexible supply arrangements and price volatility; particularly since the incidence of constraints on gas supply from Maui field following the contract quantity re-determination in 2003.

There is a significant body of opinion in New Zealand that holds a view of an impending gas shortfall from the second half of the next decade. LNG is seen as a plausible backstop.

Gas hydrates represent an alternative to imported LNG as the backstop, with further scope for export of LNG and/or other value-added product such as methanol. This study shows that, given the information we have currently, the economics of hydrates extraction when compared against LNG as a shadow price strongly indicates that gas hydrates may well be a lower cost option.

Sensitivity analyses in this study, which doubled capital costs and reduced the LNG shadow price, still support the hydrates case. The economic analysis also demonstrates that bringing gas hydrates development forward improves the overall economic case for exploration and development.

An export orientated hydrates development could also complete the integration of the New Zealand energy market into the global energy market, and establish a long-term competitive advantage for the country.

New Zealand's understanding of the prospectivity of its continental shelf regions is still relatively immature. There is a range of possible onshore and offshore sources of petroleum supply, including traditional oil/gas, lignite coals, and coal bed methane as well as the hydrates. However none of these possibilities can yet be banked, and some may prove of only incremental significance. It is premature to count on any one of these to obviate the need to consider any of the others.

It can thus be argued that this country's (via Contact and Genesis' "Gasbridge" initiative) present reliance on LNG as the sole backstop to future natural gas supply presents a significant opportunity cost and potential loss of value to the country.

We should also not lose sight of the value that can be ascribed to an improved and diverse reserves position and the security that derives from being less exposed to international supply and pricing volatilities. Our frontier resources should thus be seen as a critical strategic and economic endowment for today's and future generations.

Moving forward requires that we assess all opportunities available to us beyond just CNG imports. In evaluating a resource opportunities, there are several questions that need to be addressed. A stage gate process that allows full comparison of the different options is recommended. Such a process requires the following information (not meant to be inclusive) to be established:

- The extent and characteristics of the resource;
- The feasibility of resource recovery;
- The technical feasibility of production on a commercial scale;
- The commercial feasibility of production and utilisation;
- The social and environmental acceptability of the selected development scenario;
- The availability of the necessary infrastructure requirements including a skilled workforce;
- The factors involved in implementation of any option and initial strategies for implementation;
- Compatibly with national policy objectives.

The collective experience of the study team reinforces the importance of anticipating early those issues likely to critically affect any particular development or option. An awareness of these issues ensures that the analysis net is cast sufficiently widely to provide the fullest information on whether to proceed or terminate investigations.

7.3 Contingencies

Of course, none of the above precludes the possibility that a major natural gas discovery could be made further in the future and thus the business case for marine gas hydrate development may be delayed. Until that time, however, no one solution can be banked. Moving down the pathway suggested is not about picking winners but is, instead, intended to ensure that there is a full field of qualified runners; giving recognition to the uncertainties in the New Zealand energy market and the desirability of having diversity of opportunity.

Another point raised is at what point does the advancement of one option start to exclude others? For example, if a commercial decision is taken in respect of LNG, then does this forestall investment in other options? What this study shows is that hydrates may well be a lower cost option to imported LNG and that there may well be a range of other development options available to a hydrate development, irrespective of any decision on LNG.

Clearly, if a gas shortfall occurred in the middle of the next decade, i.e. earlier than the hydrates option is expected to be practical, LNG imports would go ahead (and thus it is important that LNG investigations continue); but in parallel, it is vital that we continue to advance work on hydrates so that a more informed decision can be made.

A core question not answered by this preliminary work is what the optimal development technology option might be? This question goes beyond the current scope but, irrespective, we comment that such questions are essentially commercial decisions best undertaken by those who ultimately have the responsibility for the "doing" of the project.

The most appropriate approach at this stage is to ensure that the commercial environment exists in which the incentives facing the private sector participants lead to investment decisions on their part that correspond to, and are aligned with, the national interest.

7.4 Concluding Remarks

Figure 7.1 provides an outline of a proposed staged development process for a prospective hydrates oportunity in New Zealand. To progress with the investigative phase, we have to understand the character of the resource (Figure 7.1: Stage 1) in more detail and also do more to catch up with international experience in the geo-technical setting of marine hydrate systems and the geological engineering factors that govern their extraction and methane recovery. Appendix 5 sets out some areas for future research to better characterise the New Zealand gas hydrates endowment.

There are a lot of uncertainties that need to be addressed before a commercial proposition can be established (Figure 7.1: Stage 2). While much of the technology may be conventional, what this study shows is that beyond the scientific knowledge that already exists it will be essential to any New Zealand effort that we gain access to the industry expertise operating internationally in this field and that we bring together the requisite mix of science and engineering knowledge and expertise to develop our own unique solutions applicable to the particular settings that exist within the prospective gas hydrate provinces identified.

We acknowledge that there is not a perfect universal model for this type of development. Our review of the international hydrates development activities suggests, however, there is room for improvement and efficiency in expediting the handover from research to commercially disciplined stages of investigation.

For New Zealand, therefore, to get ahead of the game we need to think in terms of a targeted programme directly applicable to our resources, energy market situation and the overall structure of our economy. As this study shows, there are many benefits for New Zealand from the early implementation of an engineered and optimised solution. Ultimately, it is about completion - reliance on science effort alone will not provide the right mix of ingredients to effectively complete the required appraisals for commercialisation of the hydrates.

Currently, where New Zealand sits is that we do not have the critical mass to engage

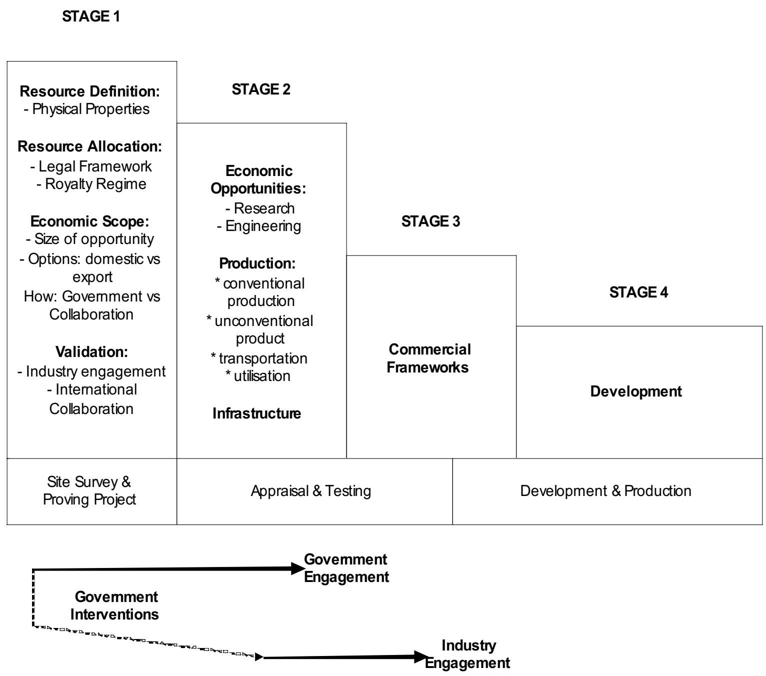

Figure 7.1: Staged Development Outline

properly and fully in international efforts except (barely) at the scientific forum level. We need to look also towards the service industries to develop relevant expertise, and to design and implement programmes which will encourage the early involvement of commercial interests in the engineering investigations and the development of engineered solutions to establish the viability of hydrates development.

This will require that a general framework of investigations be established, with designated review points, in order that the areas of primary importance are properly assessed and that information enabling evaluation is available at each of the review points as required. This in its own right will be a significant body of work undertaken over several years. It does not seem essential to us that future science effort be targeted to the conduct of a pilot production project. There are other options available to us. The following diagram illustrates how a staged development might look.

The way forward requires a procurement path that gives confidence and provides options. Whilst we can continue to count on conventional models for international science collaboration to provide the necessary leverage and traction to scientific research underway in this country, advancement of the commercial opportunity requires that New Zealand brings together a critical mass of key players capable of interacting and networking right across the supply chain.

We suggest any future New Zealand initiative should be designed around how best to stage any development pathway. This is a judgment to be made by others and will be largely determined by the market as it opens, and the risk perceptions at the time. We note that the Korean government has earmarked over US$250 million to form a national development team within the state owned Korea National Oil Company. The required investment to bring any future proposal forward thus will be significant.

Table 7.1 on the following page provides a suggested notional development pathway for a prospective future New Zealand gas hydrates initiative. It outlines the types of activities and time frames that might apply. Further work is required to fully assess the particular resource opportunity and the development programme that might ensue.

	Intended Outcomes
2008-2010	1. Commencement of a programme of resource characterisation and seismic data acquisition; 2. Development of the business and science case for a New Zealand gas hydrates initiative; 3. Development of the business case for NZ participation in selected international programmes, e.g. the Gulf of Mexico Joint Industry Programme, the Korean Gas Hydrates programme etc 4. Increased attraction of international collaborations to New Zealand (e.g. IFM-GEOMAR cruise in 2010); 5. Development of an allocation regime for New Zealand hydrates; 6. Ongoing project assessment and conceptual studies, including preliminary geological and technology assessments, engineers appraisal opportunity definition/investment boundaries;
2010-2012	7. New Zealand participation in selected international programmes; 8. Designation of a site for a New Zealand based hydrates initiative; 9. Preliminary feasibility and engineering studies, including: • Industry Engagement; • Investment Decision-Making Framework; • Environmental Impact Assessment; • Legal and regulatory reviews; • Technology Assessments/Infrastructure Options; • Economic Projections.
2012-2014	10. Detailed Feasibility & Financial Assessments; 11. Commencement of a drilling and production testing programme; 12. Identification of production site; 13. FEED and associated infrastructure planning; 14. Finalisation of construction contracts and due diligence processes; 15. Finalisation of commercial and market arrangements; 16. Development structure and venture arrangements finalised;
2014-2022	17. Construction and commissioning of facilities commences;
2022-onwards	Ongoing operations.

Table 7.1: Notional New Zealand Gas Hydrates Development Pathway

8. CONCLUSIONS

The successful development of the marine gas hydrates resources of New Zealand will require extensive ongoing research and in-depth investigation over many years. What this study has shown is that gas hydrates offer a real opportunity to make a significant contribution to New Zealand's longer-term energy requirements and, based on the information currently available, accelerating their development offers the potential for significant increased economic benefit to New Zealand. This resource class is of such a scale that, contingent on the successful development of commercial production technology, marine gas hydrate could underpin New Zealand's future energy supply system and also form the basis for new export industries.

New Zealand has access to enormous coastal marine methane gas hydrate deposits. Whilst a means for commercial recovery of this resource has yet to be proven initial surveys and the research undertaken to date suggests that the Hikurangi margin, off the East Coast of the lower North Island contains potentially recoverable natural gas reserves many-fold that represented by the known conventional natural gas reserves (including that already produced) available from the Taranaki Basin.

How much of the New Zealand hydrate's resource might be economically recoverable and at what production cost is yet unknown; but even at the most conservative level, estimates suggest that the potential volumes of natural gas available offers a transformational opportunity available to New Zealand that can not be ignored.

Estimates of the volume of recoverable gas are of the order of 813 Tcf over an area of approximately 50,000 km^2.

In addition to the relatively high distribution of indicated "sweet" spots available for exploration, the accessibility and proximity of the Hikurangi Margin to major population centres and existing natural gas distribution infrastructure offers special advantage.

At approximately 20 km off shore and around 1200-1800m depth, these offshore reserves also have significant spatial and physical advantage over most of the other key gas hydrate research sites globally. Again this has to be further evaluated.

In this study we have drawn on current research knowledge of these Hikurangi margin deposits and from information devices from international research programmes directed at gas hydrate development, develop a possible road map for the commercial production in New Zealand of natural gas from methane hydrate. This road map anticipates continuing rapid progress in the engineering geology, geological characterisation and production technologies required for hydrates extraction, and its commercial exploitation.

To this end this study has looked at a notional staged gas hydrate development plan, commencing with construction of a 10 PJ/y proving facility and expanded into a 150 PJ/y or 300 PJ/y commercial facility over a ten-year period. The economics of such a facility are as set out below. More information on the underlying rationale for the figures in Table 8.1 is described in Chapter 5 and Appendix 7.

Scenario		300 PJ Composite/10C	300 PJ Composite/10S	300 PJ
Capital Cost NZ$ million		1,300 +7,091	370+8,391	8,391
Cost of Production NZ$/GJ		3.67	3.60	3.47
IRR*	Guandong LNG price	15.4%	16.3%	17.4%
	Current LNG price	23.2%	25.0%	26.9%

Table 8.1: Internal Rates of Return under different scenarios

The information in Table 8.1 is based on the following assumptions:

- The use of LNG as the shadow price for hydrate derived methane;
- A domestic gas price of NZ$5/GJ;
- An oil price of US$60/bbl;
- A US:NZ exchange rate of 0.54;
- 300 PJ production is divided equally between domestic and export markets.

On the basis of this analysis, hydrates production would provide a significant net economic benefit relative to imported LNG. However, hydrates are unlikely to be competitive with most domestic conventional natural gas. Sensitivity analysis emphasised the importance of accelerating investigation into hydrates technology development and its customisation for New Zealand so as to reduce uncertainties regarding project costs.

Under the base case assumptions used in this study, it can be concluded that hydrates development provides a significant potential economic opportunity for New Zealand. Continued evaluation of the reserve opportunity is thus important in the event that continued limited indigenous reserves of natural gas prove insufficient to sustain current demand. Accelerating the development of the hydrates resources as an alternative to importation of LNG could significantly reduce the long-term economic cost of supplying gas to the New Zealand market.

In this respect, it is important that policy setting arrangements are put in place to encourage early investment in New Zealand's hydrates resources; otherwise, international efforts and investment will preferentially concentrate on other hydrates resource oportunities with better proximity to larger and more diverse energy markets. New Zealand could expect to be a technology-taking follower several years after the establishment of viable and value-generating marine hydrate industry elsewhere.

There is a strong and growing interest in gas hydrates internationally as a potential non-conventional energy resource to meet an impending shortage of natural gas in the developed economies. The analogue of coal bed methane, where commercial exploitation has literally leap-frogged scientific endeavour, is a useful lesson. Nowadays, this resource is providing substantial supplemental supply of natural gas into a number of international markets, for example in North America where conventional gas production capacity is in decline and offers considerable diversity in the markets.

Countries which are investing in research into the commercial development of hydrates are particularly the energy-deficient industrial economies of South Korea, Japan and India; as well as the United States and some of the European nations. For New Zealand to attract the levels of investment in research and technological expertise that characterises these programmes we will need to develop a paradigm that is quite different from the current resource development pathway that would typically be followed for a conventional petroleum resource discovery.

In this study, we explored some of the key issues that might influence these directions, and the requirements for New Zealand to be at the forefront of an emergent international gas hydrate industry. Key conclusions and observations include:

- The level of investment required for a gas hydrate development will be considerable. New Zealand has a significant opportunity to take a leadership position in international efforts to bring this technology to commercialisation. It would not be the first historic example of technological pioneering by a small country;
- To act as a pioneering nation will require considerable government leadership and intervention because unlike other economies currently active in researching hydrates development, New Zealand lacks either a national oil company or the financial and technological capacity to fund a development on its own;
- Such an effective initiative, however, will not be driven by science effort and institutional arrangements alone. Whilst the critical role of science and research is acknowledged, further advancement of the New Zealand hydrates opportunity will necessarily be technology-driven and engineering led. This will need to be supported by a regulatory and resource governance regime that is

conducive to attracting the international interests capable of providing the necessary technological know-how and risk capital to bring a commercial proposition to completion. The attraction of private and international capital will require well-conceived property rights in respect of hydrate development;

- An important contribution to this will be early support for establishment of a New Zealand gas hydrates information repository to complement existing and future MED initiatives to promote New Zealand petroleum and mineral resource opportunities. A concept plan for such a repository has been developed that integrates with MED data bases and links to New Zealand CRI information repositions holdings.

Whilst there are important lessons to be derived from the Mallik (Arctic sub-permafrost hydrate field), Gulf of Mexico, Indian and other international programmes, any New Zealand initiative will need to be more closely aligned with our own national energy and resources policies, which emphasises unlocking of such resources, and be more strongly development-focussed if such a programme is to be realised.

Collaboration will be critical but participants will need to be cognisant of commercial interests, and objectives must be aligned with New Zealand's national interests, rather than focussed on purely research and science outcomes that dominate the objectives of international research efforts.

As a pre-commercial resource opportunity, methane hydrates will require explicit treatment within the Crown Minerals regime to provide preferential considerations to support future exploitation and production. Any permitting regime will need also to take into account the reality that it is not always possible to adequately foresee future problems or even development time frames. Policy and procurement frameworks must recognise the high costs and risks associated with frontier activities of this type and thus allow for uncertainty and technological risk that might otherwise be unaccepted under normal policy settings.

We argue in this report that New Zealand should thus adopt a development pathway that seeks to arrive at a solution that properly reflects the New Zealand circumstance. It is recognised that such an approach engages Government in upstream activity much earlier than has been the recent practise but significant advantage will come from New Zealand ensuring that it has the earliest possible opportunity to develop its hydrate resources.

A more detailed analysis of the best pathway for government to establish such a framework is currently under consideration as the next stage of our work.

Ultimately, the development pathway chosen will determine research requirements. In this study we conclude that the preferred approach is a conventional framework that anticipates the way new information obtained at each stage of the investigation feeds into the overall project evaluation and gives explicit treatment to "real" options at each stage of the decision pathway. Research and technology development will best be integrated with capital allocation processes within explicit permit areas issued under the Crown Minerals Act.

Moving forward requires that New Zealand fully assesses its hydrates option against all options available for meeting our future energy needs. To this end, a "procurement pathway" is recommended that would give confidence that the investigations and assessments undertaken are robust and reflect industry norms as well as ensuring that all options are fully canvassed. It is recommended that consideration be given to the creation of a specialist corporate entity tasked and resourced to procure and carry out these activities in a non-partisan way, and which separates regulatory and commercial interests. Such an entity could would become New Zealand's counterpart to foreign government agencies and national oil companies for technical and scientific exchange, and other commercial arrangements.

Finally, we reiterate that the objective of this study was to examine the case for hydrates development in this country and the options available to New Zealand to unlock the potential of this endowment. This study has confirmed the economic potential of the resource and its importance as a transformational energy opportunity for this country. Technical development will need to embrace novel and new operating environments. Competitive factors and regulatory uncertainty will challenge conventional resource regimes, and the uncertainties that characterise frontier opportunities may well trigger public concern and opposition unless the nature of the opportunity is communicated fully and effectively.

This study also suggests that significant national benefit could accrue from early commercialisation of this opportunity.

We therefore recommend that Government develop and implement a strategic programme to bring forward the assessment of the gas hydrates resource and ongoing evaluation of the business case for gas hydrates development. This should be undertaken within the wider context of New Zealand's overall energy policy and the strategic imperative of securing for this country an improved and more diverse energy reserves position.

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APPENDICES

APPENDIX 1: Project Team Profiles

Project Team

Dr R J (George) Hooper, CAENZ

Currently Executive Director of the New Zealand Centre for Advanced Engineering, George has contributed project direction and technical input to this project. George is a professional engineer with an extensive background encompassing both the technical and the commercial fascets of the energy and natural resource sectors. Relevant previous roles include appointments as NZ executive committee member for the IEA bioenergy implementing arrangement and Chair of the New & Emerging Energy Technologies Reference Group for FoRST. George is also a fellow of the Institution of Professional Engineers New Zealand.

Mr Kevin Chong, CAENZ

Kevin Chong manages CAENZ's Frontier Resources, Patronage and Distingushed Fellows programmes. He also acts as a project manager for CAENZ projects in the energy, resources and telecommunications fields, and brings extensive New Zealand and international experience in technology commercialisation, international marketing and business strategy to this project.

Dr J M (Mac) Beggs, GeoSphere

Mac Beggs is a petroleum geologist with a PhD in Geological Sciences from the University of California, with diverse work experience in NZ and North America. He has worked as exploration geologist for BP America in Houston and Dallas identifying new oil and gas prospects off the Gulf of Mexico and monitoring exploration and planning, as well as being part of exploration, appraisal and development teams in Alaska and other North American basins.

Dr Beggs has also been closely involved with public policy in relation to ocean resources, including serving as a member of the Ministerial Advisory Committee on Oceans Policy in 2001, and contributing to work undertaken by the Ministry for the Environment during 2003 and 2004, and to work by CAENZ for MfE and Crown Minerals since 2005. His company, GeoSphere, has also completed numerous contracts for Crown Minerals, principally since 2004, assisting with provision of value-added technical information in support of Blocks Offers.

Mr John Duncan

John Duncan is an Energy Analyst and specialist in energy markets and economics. His extensive 20+ year background with oil, LPG, petrochemical and coal companies has provided him with a firm background knowledge of the technologies and economics of industrial and transportation fuels and their supply, distribution and marketing. This has been complemented by 15 years spent with energy companies, government departments and agencies, and international organisations such as the World Bank involved in the development of energy resources and markets and in energy policy and planning.

Mr John de Buerger, Transfield Worley

John de Buerger contributed expert input and capital costs estimates for the scenarios used in the analysis, drawn from Transfield Worley's cost database for New Zealand offshore and onshore oil and gas developments; in addition to evaluations of world wide progression of capabilities for drilling and production, and cycle time analysis of different development scenarios.

Mr Hamish McKinnon, University of Canterbury

Hamish McKinnon is a Masters of Engineering candidate at the Department of Chemical and Process Engineering, University of Canterbury. Hamish has worked as a Regulatory/Production Engineer prior to commencing postgraduate study. His current studies at the university are focused on biomass gasification for the production of hydrogen, utilising various bed materials to enhance the hydrogen-producing reactions.

Research Contributors

Institute of Geological and Nuclear Sciences (GNS Science)

Dr Stuart Henrys

Dr Stuart Henrys is a Senior Scientist at GNS Science in Lower Hutt who uses a range of geophysical observations to characterise gas hydrates in marine sediments. He has participated in more than 15 marine seismic surveys (seven as Chief or Co-Chief Scientist) and published ten peer reviewed papers related to gas hydrates and East Coast tectonics in the past five years. He is a member of the IODP Site Survey Panel, Australian-New Zealand IODP Science Committee, chairs the New Zealand ANDRILL Steering Committee, and is the New Zealand representative on InteMmargins. Stuart co-supervises an MSc student studying the crustal structure of the Raukumara Basin and a PhD student investigating gas hydrate resources off eastern New Zealand.

Dr Ingo Pecher

As a marine geophysicist, Dr Ingo Pecher uses geophysical techniques to study marine gas hydrates. Since 1991, his research has focused on gas hydrate deposits offshore of the US, Costa Rica, Peru, and New Zealand. He has participated in 13 marine surveys, including three as Chief or Co-chief scientist. He was also involved in laboratory studies on gas hydrates. He has published 14 peer reviewed papers in the past five years, mostly on gas hydrates, with five additional papers currently in review.

Presently, Dr Pecher is advising one and co-advising two PhD students.

Dr Vaughan Stagpoole

Dr Vaughan Stagpoole is the Oceans Exploration Section manager and Physical Resources of the Oceans programme leader at GNS Science in Lower Hutt. He is a geophysicist specialling in research on the formation and development of sedimentary basins and on basin modelling. Recently he has been involved in the assessment of the prospectivity of New Zealand's frontier sedimentary basins and the New Zealand Law of the Sea project. Vaughan has a PhD degree from Victoria University of Wellington.To be completed

Dr Philip Barnes

Philip Barnes is a marine geologist with 22 years experience the field of active continental margins. He has led numerous marine surveys and scientific projects and is a NIWA Principal Scientist. He uses geophysical, geological, bathymetric and sample data, and has published on active tectonic faulting and structure, submarine earthquake potential, sedimentation and stratigraphy, submarine landslides, canyon development, and the geological framework of fluid seep sites and gas hydrates. He has worked on a variety of consultancy projects, including marine engineering investigations for the installation of submarine pipelines, power and telecommunication cables, exploration drilling platforms, port developments, earthquake potential for seismic hazard assessments. He has been a technical expert and New Zealand delegate on the definition of New Zealand's Legal Continental Shelf project.

Dr Geoffroy Lamarche

Dr Geoffroy Lamarche is a Principal Scientist at NIWA in Wellington who has explored extensively beneath the oceans around New Zealand. He has specialized in using high resolution reflection seismic and multibeam swath data for characterisation of seafloor substrate and habitat. He is the lead scientists on a number of international science projects on the East Coast of the North Island including studies of seafloor stability. He is the NIWA representative on the New Zealand Ocean Drilling Programme (NZODP) and served on the both Technical Experts Working Group and Submission Group for the NZ Extended Continental Shelf Programme (UNCLOS).

Other Contributors

Dr Bruce Riddolls

Bruce Riddolls is a senior engineering geologist with special expertise in resource assessment and development. Bruce is a longstanding associate of CAENZ and has contributed to a wide range of resource studies for the Centre, including the South Island Lignite Assessment studies and the recent hydrates analysis. Bruce has contributed technical writing & internal review of this report.

Mr Gary Eng, Energy Markets Analyst

Gary Eng is an international specialist in energy markets and energy economics, in particular New Zealand gas market forecasting and Asian LNG trade. He has provided expert input into the modeling and analysis.

Mr Matthew Stevens, GeoSphere

Ms Yvette Hobbs, University of Canterbury
A Master's student in the Department of Engineering Geology at the University of Canterbury

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APPENDIX 3: Oceanographic Voyages and Surveys Relevent to the East Coast of the North Island

[Source: NIWA]

	Vessel	Chief Scientist	Departure	Arrival
CR1005	RV Tangaroa	Lewis, K.B.	18-Jun-73	25-Jun-73
CR1013	RV Tangaroa	Lewis, K.B.	17-Oct-73	23-Oct-73
CR1019	RV Tangaroa	Cole, A.G.	07-Apr-74	10-Apr-74
CR1028	RV Tangaroa	Brodie, J.W.	08-Jan-75	10-Jan-75
CR1049	RV Tangaroa	Lewis, K.B.	16-Sep-76	24-Sep-76
CR1064	RV Tangaroa	Dawson, E.W.	25-Aug-77	30-Aug-77
CR1082	RV Tangaroa	Lewis, K.B.	14-Oct-78	14-Oct-78
CR1086	RV Tangaroa	Dawson, E.W.	14-Dec-78	20-Dec-78
CR1139	RV Tangaroa	Carter, L.	18-Nov-82	02-Dec-82
CR1147	RV Tangaroa	Carter, L.		
CR2011	RV Rapuhia	Lewis, K.B.	12-Sep-87	18-Sep-87
CR2045	RV Rapuhia	Lewis, K.B.	03-Jul-91	08-Jul-91
CR3015	M.A. Lavrentyev	Mitchell, J.	26-Oct-93	02-Nov-93
CR3044	RV Tangaroa	Barnes, P.	4-Mar-98	17-Mar-98
CR8024	RV Rapuhia	Wright, I.C.	11-Nov-88	21-Nov-88
CR8090	Rangatahi	Carter, L	02-Aug-99	02-Aug-99
L783SP	RV S.P. Lee	Lewis, K.B.	29-Dec-83	31-Dec-83.
TAN9809	RV Tangaroa	Peter McMillan	18-Aug-98	20-Aug-98
TAN0106	RV Tangaroa	Lewis, K.B.	04-May-01	17-May-01
TAN0113	RV Tangaroa	Lamarche, G	05-Aug-01	16-Aug-01
TAN0215	RV Tangaroa	Mitchell, J.	21-Aug-02	28-Aug-02
TAN0313	RV Tangaroa	Barnes, P.	03-Aug-03	08-Aug-03
TAN0309	RV Tangaroa	Mitchell, J.	9-Jun-03	15-Jun-03
TAN0314	RV Tangaroa	Carter, L.	08-Aug-03	24-Aug-03
TAN0412	RV Tangaroa	Barnes, P.	18-Oct-04	1-Nov-04
TAN0510	RV Tangaroa	Mitchell, J.	14-Aug-05	24-Aug-05
TAN0512	RV Tangaroa	Nodder, S.	30-Sept-05	07-Oct-05
TAN0607	RV Tangaroa	Nodder, S.	04-July-06	10-Jul-06
TAN0612	RV Tangaroa	Law, C.	27-Sept-06	03-10-06
TAN0613	RV Tangaroa	Orpin A.	03-Oct-06	08-Oct-06
TAN0616	RV Tangaroa	Rowden, A.	01-Nov-06	20-Nov-06
TAN0702	RV Tangaroa	Nodder, S.	24-Jan-07	30-Jan-07
TAN0711	RV Tangaroa	Nodder, S.	29-Aug07	08-Sept-08
TAN0804	RV Tangaroa	Nodder, S.	27-April-08	04-May-08
TAN0810	RV Tangaroa	Lamarche, G	24-Jul-08	13-Aug-08

**We note that this is not a comprehensive list and acknowledge in particular the omission of details of the RV Sonne cruises of 2007.*

APPENDIX 4: Summaries of Key National Hydrates Research Programmes

Selected Summary of Gas Hydrate Research in the United States

Timeline	Description	Notes
2009	GoM JIP Leg II commences, a second field programme aboard the semi-submersible drilling vessel, the *Helix Q4000*, to test a variety of geologic/geophysical models for the occurrence of gas hydrate in sand reservoirs in deepwater GoM	
2008	US DoE/NETL announces nine new methane hydrate research projects: a) Gas Hydrates in the natural environment b) Gas Hydrate production technologies: • ConocoPhillips to field trial a method to produce free methane for production by injection of carbon dioxide into the reservoir as a replacement, on the Alaska North Slope site; • Monitoring of gas hydrate behaviour in the reservoir as a result of depressurisation from experimental production of the North Slope Borough site at Barrow, Alaska; c) Gas Hydrate exploration technologies: • Oregon State University to study of the impact of regional heat flows on continental margins as a tool to predict gas hydrate occurrences; • Scripps Institution of Oceanography to conduct CSEM surveys of 3 sites in the GoM to increase understanding of hydrate detection and characterisation using this remote sensing tool.	1
2008	The research vessel *Roger Revelle* completes an experimental survey of gas hydrates in the Gulf of Mexico over 18 days, using state-of-the art controlled source electromagnetic (CSEM) methods. 30 seafloor magnetic and electronic recorders were deployed 94 times, broadcasting 103hrs of EM signals from a towed transmitter and generating 70Gb of data. The premise for this research project was well logs and lab experiments which demonstrated that hydrate was more electrically resistive than host sediments.	2
2008	US Congress passes an omnibus spending bill in December that provides an additional US$3m (over the $12m in the previous year) in funding for NETL-managed gas hydrate R&D projects, including directed spending of $1m for the GoM hydrate consortium at the University of Mississippi	3
2008	US MMS (Minerals Management Service) releases preliminary results of the Gulf of Mexico in-place natural gas hydrate assessment, suggesting a mean volume of 607 Tcm (21,444 Tcf) in-place over a gas hydrate province 450,000 km^2 in size. A mean of 190 Tcm (6,710 Tcf) are suggested to be contained as relatively high concentration accumulations (‘sweet spots’) in relatively accessible sand reservoirs.	4
2007	US DoE releases *An Interagency 5-Year Plan for Methane Hydrate Research & Development: FY2007 to FY2011*	5
2007	BPXA concludes an extensive data collection programme at a stratigraphic test well at the Mt Elbert site on the Milne Point area of the Alaska North Slope. Key findings: • Operationally, the programme demonstrated the value of correct well-bore fluid selection and cooling; and the efficacy of some ‘first applications’ of technology at the site, including wireline retrievable coring and open-hole testing of hydrate bearing reservoir sands; • Scientifically, it validated gas prospecting methods developed by USGS when the programme encountered gas hydrates largely as predicted by the pre-well models.	6

2006	US DOE releases *An Interagency Roadmap for Methane Hydrates Research and Development*, which set out the interagency programme for hydrates R&D from 2000-2007	7, 8
2006	Chevron USA makes data collected in 2004 from the 'Tiger Shark' area available to the research community that provided the first confirmation of the presence of a thick zone of gas hydrate saturated sandstone in the Go M. The data also represented the first known full suite of geophysical well logs taken by the oil and gas industry across the gas hydrate stability zone in the Gulf.	9
2005	US Congress passes *The Energy Policy Act (2005)*, which extends the provisions of *The Methane Hydrates R&D Act (2000)* and provides production incentives (suspension/reduction of royalties), hydrates specific research funding within oil & gas programmes, and specific funding for hydrates research & development programme	10
2005	GoM Leg I, the first major field project by the ChevronTexaco JIP, commences – a 35 day multi-hole drilling programme in the Keathely Canyon & Atwater Valley in the Gulf of Mexico using the semi-submersible drilling vessel, the *Uncle John.*	11, 12,
2004	The National Research Council (NRC) Committee to Review the Activities Authorised Under the Methane Hydrate Research and Development Act 2000, as mandated by the Methane Hydrate R&D Act (2000), publishes *Charting the Future of Methane Hydrate Research In The United States*	13
2002	US DoE funding commences towards the ChevronTexaco Joint Industry Project (JIP) in the Gulf of Mexico, the largest and most prominent of the DOE funded hydrates projects. The project was focused on developing a better understanding the properties of gas hydrates in deepwater Gulf of Mexico and their effects on seafloor and well bore stability DoE contribution budget was USD$10.6m from 2002 to 2005	14
2002	Phase 1 of BP Exploration Alaska (BPXA) Project commences to investigate gas hydrate reservoir characteristics, including distribution and concentration of hydrates, in the Eileen Field area on the Alaska North Slope DoE contributed USD$2.4m to 2004 vs $5.9m from BPXA	15
2002	Ocean Drilling Programme Leg 204 commences on Hydrate Ridge offshore Oregon, USA. This drilling programme over 9 sites is focused on understanding the distribution of gas hydrate in marine sediments. DoE contributed USD$1.4m to the leg vs cost of the entire leg of approximately $12m	16
2002	The Mallik 2002 International Gas Hydrate Production Research Well Programme commences in the McKenzie Delta in Canada, led by the Geological Survey of Canada (GSC) and the Japan National Oil Company (JNOC). The DoE Methane Hydrate R&D Programme was one of 8 partners in a multidisciplinary scientific and engineering programme	17
2000	US Congress passes the *Methane Hydrate Research and Development Act (2000)*, authorising DoE, in consultation with US Geological Survey (USGS), US Minerals Management Service (MMS), the National Oceanic & Atmospheric Administration (NOAA), the National Science Foundation (NSF) and the Naval Research Laboratory (NRL), to conduct methane hydrate research. Funding of USD$47.5m is authorised for 5 years from 2001 This Act mandates the establishment of two committees to provide scientific oversight of the DoE Methane Hydrate R&D programme:	18, 19, 20 21 22

	• The Methane Hydrate Advisory Committee (MHAC): to advise the Secretary of Energy on potential applications of methane hydrate; • The Interagency Coordinating Committee (ICC): to review the progress of the programme and make recommendations for future research	
1999	US DoE releases *A National Methane Hydrate Multi-Year R&D Programme Plan*	23
1998	US DoE releases *A Strategy for Methane Hydrates Research and Development*	24
1988	US Department of Energy (DoE) commences a10-year, USD$8m programme to study hydrates in the wild	25

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13. Fire in the Ice: Methane Hydrates Newsletter. Spring 2005:10
14. Charting the Future of Methane Hydrate Research in the United States. 2004. (ibid).
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22. Charting the Future of Methane Hydrate Research in the United States. 2004: p18
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24. Charting the Future of Methane Hydrate Research in the United States. 2004: p2
25. Charting the Future of Methane Hydrate Research in the United States. 2004: p2
26. Charting the Future of Methane Hydrate Research in the United States. 2004: p18

Selected Summary of Gas Hydrates Research in India

Timeline	Description	Notes
2009 – 2010	NGHP Expedition 02 may be constituted to drill and log several of the most promising gas hydrate sand-dominated prospects	[7]
April 2009	(Indian) National Institute of Ocean Technology NIOT to start coring in Krishna-Godavari basin. Vessel " Sagar Nidhi" ex Fincantieri shipyards. **Indo – Russian Centre for gas hydrates** Joint collaborative research activity shall deliver new pathways for the gas hydrate studies which is still at its infancy in global scenario. Following are the major projects under the Centre. 1. Geology of gas hydrates (NIO) 2. Natural processes involving gas hydrates (NGRI) 3. Estimations and modeling of gas hydrates resources (NGRI) 4. Physical, chemical, mechanical and other basic properties of gas hydrates (NGRI) 5. Technology of recovery, purification and transportation of gas from gas hydrates deposits (NIOT) 6. Ecological aspects of gas hydrates processing (NIO) 7. Economics of gas hydrates resources exploitation (NIO) 8. Joint research of Gas Hydrate in Lake Baikal and its application to Indian conditions (NIOT) 9. Design and develop necessary instruments and observing devices to address above mentioned scientific and technical problems (NIOT) To implement the above projects an "Indo Russian Centre for Gas Hydrate Studies (IRCGHS)" is established at NIOT, Chennai as per the Memorandum of Understanding (MoU) between the Russian Academy of sciences (RAS), Russia and the Department of Science and Technology (DST), India.	[8]
17 July 2008	Mr Jairam Ramesh, Union Minister of State for Power: "I don't see it (gas from gas hydrates) coming in the next five years, but I am sure that in the next 10 years, it will be an important source of energy. According to the DGH[1], the delay in the programme taking off was because of "non availability of a suitable deepwater drill-ship with onboard laboratories and experienced staff	[5]
6 – 8 Feb 2008	NGHP Expedition-01 results reported (ref 7): • Delineated and sampled one of the richest marine gas hydrate accumulations ever discovered (Site NGHP-01-10 in the Krishna-Godavari Basin) (depth 950 m and 40 mbsf.). • Discovered one of the thickest and deepest gas hydrate occurrences yet known (offshore of the Andaman Islands, Site NGHP-01-17) which revealed gas-hydrate-bearing volcanic ash layers as deep as 600 meters below the seafloor. • Established the existence of a fully developed gas hydrate system in the Mahanadi Basin of the Bay of Bengal. • Most of the gas hydrate occurrences discovered during this expedition appear to contain mostly methane which was generated by microbial processes. However, there is also evidence of a thermal origin for a portion	[7] [9]

	of the gas within the hydrates of the Mahanadi Basin and the Andaman offshore area. NGHP Expedition 01 has shown that conventional sand and fractured-clay reservoirs are the primary emerging economic targets for gas hydrate production in India. Because conventional marine exploration and production technologies favor the sand-dominated gas hydrate reservoirs, investigation of sand reservoirs will likely have a higher near-term priority in the NGHP program. Directorate General of Hydrocarbons Director General and NGHP Program Coordinator V. K. Sibal said, "…The Indian gas hydrate program has been fortunate in having the benefits of a truly global collaboration in the form of the first gas hydrate expedition in Indian waters. ... I believe that the time to realize gas hydrate as a critical energy resource has come." Total cost $37M.	
28 April - 19 August 2006	Scientific Research Drill Ship "JOIDES Resolution" sails from Mumbai, commences core drilling, with limited support from US DOE. The ship will explore prospective gas hydrate fields along the western coast in Konkan, the Krishna Godavari basin, Mahanadi and areas around the Andaman seas. he exploration will be conducted under India's National Gas Hydrate Program (NGHP) of the Directorate General of Hydrocarbons[2]	
September 2007	Indo-Russian program collects 1.2m core sample of Gas Hydrate from Lake Baikal (Rus). Eight joint projects underway.	[10]
1 May 2005	India's Union Minister for Petroleum and Natural Gas, is quoted as saying "that total prognosticated resource of offshore gas hydrates in India was 1,894 trillion cubic metres, 1,900 times the country's current gas reserves"	[5]
1998	Resource estimation and delineation of prospective areas for methane hydrate has been done Krishna–Godavari and Andaman–Nicobar Islands may be explored for hydrates. About 7.5 Tcm of methane is estimated in an area of about 80,000 km^2 from Indian deep offshores, which is about 5 times the total conventional gas reserves of the country Indian continental margins (especially on the east coast in Bay of Bengal) with excess sedimentation rate and organic carbon content than required for methane hydrate production are the potential sites for methane hydrate exploration. The physical parameters (temperature, pressure, salinity) controlling the formation of methane hydrate are also met at the site at a water depth ranging from 650 m (east coast) to 750 m (west coast)	[2] [3]

2 NGHP Expedition 01 was planned and managed through a collaboration between the Directorate General of Hydrocarbons (DGH) under the Ministry of Petroleum and Natural Gas (Government of India), the U.S. Geological Survey (USGS), and the Consortium for Scientific Methane Hydrate Investigations (CSMHI) led by Overseas Drilling Limited (ODL) and FUGRO McClelland Marine Geosciences (FUGRO). The platform for the drilling operation was the research drill ship JOIDES Resolution (JR), operated by ODL. Much of the drilling/coring equipment used was provided by the Integrated Ocean Drilling Program (IODP) through a loan agreement with the US National Science Foundation (NSF). Wireline pressure coring systems and supporting laboratories were provided by IODP/Texas A&M University (TAMU), FUGRO, USGS, U.S. Department of Energy (USDOE) and HYACINTH/GeoTek. Downhole logging operational and technical support was provided by Lamont-Doherty Earth Observatory (LDEO) of Columbia University

Notes:

[1] A. Singh and B. D. Singh, Birbal Sahni Institute of Palaeobotany

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[5] http://www.thehindubusinessline.com

[6] Indian National Gas Hydrate Program Gas Hydrate Conference held February 6-8, 2008 in New Delhi, India

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[8] http://timesofindia.indiatimes.com/Earth/India_goes_deep-sea_diving_for_clean_fuel/articleshow/3653330.cms

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Selected Summary of Gas Hydrates Research in South Korea

Timeline	Description	Notes
Early 2009	SK intends in participating in US pilot project at Alaska North Slope	[11], [14]
Sep/Oct 2008	Knowledge-Economy Minister Lee Youn-Ho attended a meeting of the National Assembly's Special Committee on the Stability of People's Livelihood and said, "If the gas hydrates near Dokdo are developed, it would help safeguard our territorial rights and secure new energy sources that we currently lack in our country."	[14]
September 2008	Research into methane hydrate extraction using coincident CO2 sequestration published in Fluid Phase Equilibria 274 (2008) 68–72. Research institutions: Gasification Research Center, Korea Institute of Energy Research,, Department of Environmental Engineering, Kongju National University, Zero Emission Technology Research Center, Korea Institute of Energy Research Other Institutions include: Korea Adv Inst Sci & Technol, Dept Chem & Biomol Engn, Korea Inst Geosci & Mineral Resources	[19]
18 April 2008	Energy Secretary Samuel Bodman and South Korea Minister Lee Youn-ho signed a Statement of Intent to exchange information on gas hydrate topics and technologies	[11], [14]
[check date]	Research being conducted at Korea Advanced Institute of Science and Technology (KAIST), in association with Georgia Institute of Technology, supported by Basic Research Program of the Korea Science & Engineering Foundation (KOSEF; Grant No. R01-2006- 000-10727-0) and the DOE Joint Industry Project for Methane Hydrate administered by Chevron (Also at Seoul National University and Pusan University)	[17]
23 Nov 2007	SK government (Ministry of Commerce, Industry and Energy[1]) reports discovery of 600million MT gas hydrate, 99% methane, 135km northeast of Pohang (East Sea = Sea of Japan), near Donghae gas field in Ulleung Basin. Supply estimated at 30 years consumption. This is in close proximity to the island of Dokdo which is the crux of an ongoing territorial dispute between SK and Japan (and which seems to receive a lot of press including on Arirang TV) Ship: 2,000-ton South Korean oil drilling ship Tamhae 2 (3D seismic research vessel) "The drill hit the sea bottom at 2,072 meters and found a gas hydrate deposit after digging several more meters," Lee said, disclosing that the gas pool appeared 6.5 meters below the sea bed. 130m thickness is much greater than Japanese, Indian and Chinese reserves (SK LNG imports increased 18% in the year to April 2008)	[12] [16]
Dec 2006	Signing of the ``8th Executive Protocol of Italy-Korea scientific and technological cooperation (2007-2009), including joint research into Integrated analysis of geophysical data to characterise the gas hydrate reservoir offshore South Shetland Margin (National Institute of Oceanography and Experimental Geo physics, Trieste/Korea Polar Research Institute, Ansan)	[18]

2005 – 2007	The Korean government invested 66.7 billion won (US$66.87 million) from 2005 to 2007 to find and determine the size of hydrate deposits, and plans to spend an additional 85 billion won through 2011	[15]
July 2005	SK Government forms national development team with state owned Korea National Oil, Korea Gas and the Korea Institute of Geoscience and Mineral Resources. $243.5million earmarked for the project until 2014	[12]

Notes:

[11] http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/MH_Highlights_Archive.html

[12] http://www.platts.com/Natural%20Gas/Resources/News%20Features/asiapacificlng/korea.xml

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1 http://www.mke.go.kr/ (South Korean Ministry of the Knowledge Economy - Korean language)

Selected Summary of Gas Hydrate Research in Japan

Timeline	Description	Notes
2016	Estimated full production start date, corresponding with completion of 16-year test and development programme	[20]
2012 – 2016	Preparation for Commercial Production: Phase 3 of Japan's Methane Hydrate Exploitation Program	[22]
2009 (- 2012)	Test drilling scheduled /in Japanese Waters (Nankai Trough) (Phase 2 of Japan's Methane Hydrate Exploitation program)	[20]/, [21], [22]
[check date]	Calculated estimates of methane hydrate and natural gas deposited in Nankai Trough are between16 to 27 trillion m^3. MH site concentrations favour southwest margin cf. northeast.	[26]
31 Oct 08	Japanese Government Headquarters for Ocean Policy decides to apply to the UN for a larger continental shelf claim	[32]
October 2008	Japanese and Indian Economics Ministers meet, issue a statement of cooperation on several development projects (not explicitly including methane hydrates)	[29]
August 2008	UPI Asia reports JOGMEC admits that only half of the Nankai Trough methane hydrate store is recoverable using conventional drilling techniques, owing to lower densities. Ryo Matsumoto (see below) also indicates that drilling may not go ahead, if current suspicions that only 30% of Nankai Trough deposit is recoverable within 8 years. Matsumoto also favours drilling in the Sea of Japan (Korean East Sea), highlighting shallower depths (3200ft water and 300ft seabed in sand cf. 6500ft water and 700ft seabed in mud in Nankai Trough). BUT drilling in mud requires different drilling techniques to that already proven. Aoyama (see below) analyses that increased US-Japanese cooperation may be the Japanese government's goal, in favour of US cooperation with Korea, which would lessen the chances of Japan controlling the Sea of Japan/Korean East Sea deposit.	[35]
July 2008	US Board on Geographic Names, removes title of Korean ownership of Dokdo/Takeshima Island in East Sea/Sea of Japan	[36]
14 April 2008	Japanese (Jogmec)/Canadian MH drilling expedition report methane production for six straight days (Mallik site) (Hot water injection production method)	[21] [23]
December 2007 – March 2008	Inpex Corporation releases statement of involvement in Jogmec's "Feasibility Study for Natural Gas Hydrate Ocean Transportation Chain", with the aim of increased monetization of stranded natural gas resources.	[30]
December 2007	Nankai Trough MH deposit (30mi from main Honshu Island) estimated at 39 Tcf, water depth 500m (39 Tcf = 1.1 Tm^3). Estimated total 7.4 Tm^3 = 262 Tcf, thought to be world's largest "Conventional drilling technologies won't be applied for methane hydrate exploitation.'' – K Yokoi (see below) Depressurising shown to be most efficient drilling method	[20] [23] [21] [27] [20] [20]
April 2007	Jogmec and Canadian Government complete first round of drilling tests. Results unknown, subject to confidentiality agreement	[20]
2006	Japanese LNG imports total 3.03 Tcf, value $23.3B	[20]
2006	Matsumoto (see below) and colleagues discover methane gas bubbles rising from ocean floor	[20]
2005	Japanese government estimates MH drilling to be economically viable when oil trades above $54/barrel	[20]
2004	Methane Hydrate deposit calculated (estimated) at 250 Tcf in-place, located only in sand layers, filling pore spaces between grains. Methane Hydrate primarily biogenic, concentrated from lower limit of stability zone upward 70m	[25]

2003	Presentation given at Geological Society of America Seattle Annual Meeting, by Y Okuda of AIST (see below) identifies Nankai Trough as region which is "normally difficult for convention oil and natural gas fields to exist". Goes on to identify geological phenomena affecting the change of methane hydrate deposits	[28]
25 Dec 2001 – 14 Mar 02	Japex Canada and JNOC participate in first production well drilling at Mallik Site, Mackenzie Delta, Canada	[31]
2001 – 2002	Seismic Survey Campaign undertaken in Nankai Trough. 2802km² 2-D surveyed, 1960km² 3-D surveyed	[24]
2001	MH21 Research Consortium for Methane Hydrate Resources in Japan ("MH21 Research Consortium") established, headed by S Tanaka (see below) to implement Phase 1 of Japan's MHEP 3 Subsidiary Groups: Research Group for Resources Assessment (Jogmec (see K Yokoi below)); Research Group for Production Method and Modelling (National Institute of Advanced Industrial Science and Technology (AIST)); Research Group for Environmental Impact (Engineering Advanced Association of Japan (ENAA))	[22]
2001 – 2008	Phase 1 of Japan's Methane Hydrate Exploitation Program (MHEP)	[22]
July 2001	Document "Japan's Methane Hydrate Exploitation Program" prepared by Advisory Committee for National Methane Hydrate Exploitation Program, within Ministry of Economy Trade and Industry, led by Shoichi Tanaka (see below). "The project is intended to promote technical development for economical drilling, production and recovery of methane hydrate, and to facilitate its utilization and contribution to the long-term stable energy supply. The project defines methane hydrate as a future energy resource that is expected to exist in large amounts offshore around Japan." Goals: 1. Understand the conditions and features of methane hydrate existing offshore around Japan. 2. Estimate the amount of methane gas in the hydrated area. 3. Select methane hydrate resource fields from the potential sea areas and study their economic feasibility. 4. Implement methane hydrate production tests in the selected resource fields. 5. Develop technologies for commercial production. 6. Establish the exploitation system considering environmental preservation.	[22]
1 Apr 01	New Energy Resources (NER) Research Centre established at Kitami Institute of Technology	[33]
1999	Japanese scientists drill 3 wells at a Tokyo Bay site, 50km off Japanese coast at water depth 950m. Depth to BSR 290mbsf, 1240m bmsl. MH occurred between 1150 and 1210m, filling 20% of volume and 80% of pre space. Volume calculated at 525Mm³/km².	
1995 -	Japan National Oil Corporation (JNOC, obsolete) begins research into Methane Hydrates, spends $60M.	[23] [34]
1987 -	Ryo Matsumoto, University of Tokyo begins MH research	[20]

Notes:

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[21] The Times Online, "Japan's Arctic methane hydrate haul raises environment fears", 14 April 2008. http://www.timesonline.co.uk/tol/news/environment/article3740036.ece

[22] MH21 Research Consortium website, http://www.mh21japan.gr.jp/english/mh21-2.html

[23] Japan Oil, Gas and Metals National Corporation (Jogmec) website: http://www.jogmec.go.jp/english/activities/technology_oil/promoting.html

[24] JNOC Presentation at Rice University http://www.rice.edu/energy/publications/docs/Fire_in_Ice_Tsuji.pdf

[25] Search and Discovery Article #10064 (2004) "An Appraisal Project for Offshore Methane Hydrate in Japan", Takatoshi Namikawa, Masaru Nakamizu, Koji Ochiai, and Yoshihiro Tsuji (all JNOC). http://www.searchanddiscovery.net/documents/2004/namikawa/index.htm

[26] NETL, US DoE: http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/about-hydrates/nankai-trough.htm

[27] NGV Global, "USA and Japan Agree to Joint Methane Hydrate Study", 23 May 2008. http://www.ngvglobal.com/en/technology/usa-and-japan-agree-to-joint-methane-hydrate-study-01891.html

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[32] The Yomiuri Shimbun, "Government to make larger continental shelf claim", 1 November 2008. http://www.yomiuri.co.jp/dy/national/20081101TDY01303.htm

[33] New Energy Resources (NER) Research Centre, Kitami Institute of Technology. http://www-ner.office.kitami-it.ac.jp/index-e.html

[34] RAND Corporation: "Fire and Ice". http://www.rand.org/scitech/stpi/ourfuture/GameChangers/fireice.html

[35] UPI Asia, "Japan pursues new energy source", 28 August 2008. http://www.upiasia.com/Politics/2008/08/28/japan_pursues_new_energy_source/4062/

[36] Reuters, "U.S. backs away from S.Korea-Japan island dispute", 30 July 2008. http://www.reuters.com/article/worldNews/idUSN3029250220080730

Personalities	
Aoyama, Chiharu	Director of the Natural Sciences section at Japan's Independent Institute Co., Ltd.
Hashiba, Yoshifumi	Deputy Director of Petroleum and Natural Gas Division, Japanese Ministry of Economy, Trade and Industry
Matsumoto, Ryo	University of Tokyo Scientist. Attributes natural gasification of methane hydrates following seismic event to be a major cause of global mass extinction.
Nikai, Toshihiro	Minister of Economy, Trade and Industry, Japan
Okuda, Yoshihisa	Geological Survey Japan, National Institute of Advanced Industrial Science and Technology (AIST)
Okui, Toshiharu	Deputy General Manager of Gas Resources, Tokyo Gas Co., (largest Japanese distributor of natural gas)
Tanaka, Shoichi	Professor Emeritus, University of Tokyo. Led Advisory Committee for National Methane Hydrate Exploitation Program in 2001.
Yokoi, Kenichi	Team Leader of Methane Hydrate Research Project, Japan Oil, Gas and Metals National Corporation (Jogmec, govt-controlled)

Inpex Corporation	http://www.inpex.co.jp/nglish/business/rd/rd01.html
Japan Drilling Company	http://www.jdc.co.jp/english_site/aboutjdc.html. Company in charge of "Technical Verification Tests and Experiments", "FEED (Front End Engineering and Design) for Offshore Methane Hydrate Production Test", and "Feasibility Study of the Methane Hydrate Development System"
Japan's Independent Institute Co., Ltd.	http://www.dokken.co.jp/en/cp/index.html
Japanese oil, Gas and Metal National Corporation	(Jogmec) http://www.jogmec.go.jp/nglish/
Japan Petroleum Exploration Co. Ltd.	(Japex) http://www.japex.co.jp/nglish/technology/methane.html#
MH21 Research Consortium	
Ministry of Economy, Trade and Industry	http://www.meti.go.jp/english/index.html (see Agency for Natural Resources and Energy)
New Energy and Industrial Technology Development Organisation	(NEDO) http://www.nedo.go.jp/english/
New Energy Resources (NER) Research Centre	http://www-ner.office.kitami-it.ac.jp/index-e.html . Features international collaboration with Russia, Belgium, Germany and Korea.
Schlumberger in Japan	http://www.slb.co.jp/english/company/index.htm

APPENDIX 5: Future Assessment Work

The objective in designing further investigations is to produce a sufficiently detailed and accurate predictive model to support engineering studies towards a specific development scheme and a subsequent investment decisions.

Key resource issues to be considered include:

1. the spatial distribution of gas hydrates and the thickness of the GH stability zone (GHSZ).
2. The thermal structure in the upper 1 km of subsurface for improved GH modelling.
3. The potential volume of the methane resource.
4. How to improve estimates of methane concentrations in the GHSZ, both from seismic records or surface features (morphology, chemistry, biology).
5. Methane source and chemistry, via analysis of methane gas, fluids, fauna and carbonate at seabed seep sites,
6. How to improve identification of methane concentration sweet spots.
7. The physical framework of the gas hydrates, including relationships between gas hydrates and free gas concentrations to bathymetric features, to sedimentation cover and rate, and to geological structures and stratigraphy that provide permeability, focussing fluid and gas flow from deeper sources to reservoir, and from the GH reservoir to the seafloor at sites of natural leakage,
8. Where the resource is currently perturbed with free gas seepage at the seabed, and what flow rates at such sites of leakage occur naturally,
9. Capability to map methane distribution in bottom waters via in situ sensors in towed array

Resource data requirements include:

1. Widespread 2D seismic reflection data with various frequency contents and image resolution, including industry-standard, long streamer multichannel seismic data capable of providing high quality velocity control and advanced specific processing.
2. Hi-frequency seismic data for evaluating spatial variability of hydrate and free gas, as well as associated structural and stratigraphic controls on GH formation and distribution.
3. Selected 3D seismic data acquisition at selected sites of inferred methane hot spots.
4. Very-high frequency seismic profiling for substrate characterisation at such potential hot spots, particularly if seafloor engineering is to proceed.
5. Wider coverage of high-resolution (30 kHz) multibeam bathymetric data to underpin resource evaluation, seismic planning and interpretation, sample planning, and future submarine engineering planning and activities.
6. High resolution mapping of the spatial extent and ecological structure of ephemeral seep communities as an indicator of hydrate resource size.
7. Widespread seafloor sampling coupled with photography and video for characterisation of gas hydrate distribution, providing samples for relevant sedimentary and geotechnical analysis. Currently gas hydrates recovered from only one site.
8. Bottom water methane mapping
9. Physical sampling by exploration drilling combined with borehole measurements will be required to appraise individual reservoirs.

Environmental data requirements include:

1. Further exploration using high resolution acoustics and seabed video surveys to assess the full extent of active seep sites on the Hikurangi Margin.
2. Identification, quantification and mapping of chemosynthetic assemblages (from bacteria to megafauna) to evaluate composition and spatial distribution, and evolutionary relationships with other biogeographic regions.

3. Trophic studies using stable isotope analysis to determine rates of carbon uptake and how important the transfer of biological production from chemosynthetic assemblages is to non-seep fauna in surrounding habitats.
4. Research to assess the age of assemblages, degree of population connectivity between sites, and likely rates of recolonisation following disturbance.

APPENDIX 6: Preliminary Well Development Plan (PREPARED BY TRANSFIELD WORLEY SERVICES)

TRANSFIELD WORLEY SERVICES

CAENZ

Preliminary Development Plan

New Zealand Offshore Gas Hydrates

501102-RPT-X0001

March 2009

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SYNOPSIS

This report gives a first pass indication of the facilities and equipment required to produce natural gas from the gas hydrate deposits believed to lie in deep water off the Eastern coast of the North Island. It is based on the general concepts outlined in the Hancock paper as presented to the NZ Petroleum Conference in May 2008.

As requested by CAENZ, TWNZ have further developed these concepts, and made a preliminary costing of the facilities envisaged.

Only two scenarios have been considered- the 10PJ "proof of concept phase", and the 150 PJ case, which assumes no further major conventional gas discoveries, and New Zealand industry choosing to rely on local hydrate gas, rather than imported LNG.

The 300PJ LNG export case has not been studied, because in simple terms it can be considered to be a near-duplicate of the 150PJK case.

Data for concept development comes from previous and present regional work and costing comes from the TWNZ database for New Zealand offshore construction.

This report is preliminary, and being subject to time restraints was restricted to desktop study only. No approaches were made to marine or drilling contractors for current offshore pricing.

Further work is required to tighten confidence limits.

REV	DESCRIPTION	ORIG	REVIEW	TWNZ APPROVAL	DATE	CLIENT APPROVAL	DATE
A	Issued for Review	J de Bueger			02/2009	N/A	
0	Approved for Use	J de Bueger			03/2009	N/A	

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APPENDICES

1. INTRODUCTION

Gas hydrates are ice-like structures wherein molecules of water and methane gas are combined into a single lattice structure - and retained in that state by defined combinations of temperature and pressure- as shown on the appropriate phase diagram.

Huge deposits are located in Artic permafrost, and clathrates are also found below the seabed in some temperate regions of the world.

Void-filling gas hydrate deposits have been detected in sediments along New Zealand's deep water margins (800m -1000m) at depths around.300m below seabed.

It has been estimated that over an area of approx 50,000km2 off the North Island East coast, there are about 23 trillion m3 of recoverable reserves, with economically recoverable reserves probably greater than the Maui gas field. This study is based on the premise that a "sweet spot" exists 20 km off the Wairarapa coast.

While no gas is produced from clathrates anywhere in the world, considerable efforts are currently being made in several locations in order to do so. Given that the bulk of the required production technology is basically the same as required for natural gas production, there appear to be few insurmountable technical problems.

The main obstacle is cost - conventional gas wells work at considerably higher pressures, and by producing considerably more gas per well, they are economically more attractive.

When a country has no natural gas, or has depleted its conventional low cost gas reserves, the conventional method of alleviating gas shortage is by importing LNG.

As LNG is considerably more expensive than well gas, the economic decision whether to consider gas hydrate development is based on a cost comparison with relatively expensive imported LNG.

2. DEVELOPMENT PLAN

Preliminary Proving/Testing Phase

It is normal procedure on oil/gas development projects to demonstrate the viability of the project before major expenditure of the magnitude indicated in this report is contemplated.

To do this, it is necessary to produce a well or series of wells for sufficient time to convince project financiers that flow sheet design production can be expected to be achieved and that total gas production will render the project viable and bankable. Such a procedure is doubly necessary for hydrate wells, because not only are we dealing with frontier technology, but experience to date has shown that the geological composition of down-the-hole hydrate can vary widely. A CT scan of a “hydrate rich” core is essentially a 3D representation of the inter-granular porosity before it was filled by water; which in the presence of methane turned into hydrate.

Every cubic metre of hydrate disassociates into a 0.9m^3 of water and a 160-180m^3 of methane. If water has to be removed to reduce pressure so as to maintain gas production, voids will be created adjacent to the well. Should slumping and reservoir collapse occur, the potential is there to both damage the well-casing and to allow re-establishment of the pressure/temperature phase regime that maintains hydrate in the solid state.

Extended testing is the standard method of gaining confidence in such matters – with the gas usually being flared for several months.

The wells themselves are relatively shallow (only 200-300m deep) and would not be particularly expensive. The cost allowed for two off test wells is US$5 million each.

These could be drilled with a simple rig, but unfortunately the day rate for a suitable rig is not determined by the well characteristics, but by the 1000m of water depth. Appendix 10 shows the current day rates for blue-water rigs, suitable for drilling in ocean depths between 3000ft and 7500ft – and with the dynamic positioning capabilities required to be able to stay on location for extended periods.

The rig would need to be fitted out with suitable process testing equipment – very similar in principle to that required for the 10PJ case-water separation, gas lift (probably), chemical injection equipment, flaring gear and accommodation for 24 hr operations on a long-term basis. An allowance has been made for typical gear that might be envisioned.

The historical daily rate for a rig in the 3000-4000ft depth range has varied form US$80 k/day in2004 to US$420 k/day in late 2008 when oil was over $150/bbl. With the recent correction in the cost of a barrel of oil, rig rates have slipped and can be expected to ease further.

The current day rate for a suitable blue-water rig is around US$320 k/day, but it would be reasonable to expect that a lower rate could be negotiated for a drilling and extended test programme.

It is a matter of opinion as to how long a test need be, but the minimum would be until such time that the preferred production methodology has been identified for stable gas production. This would require establishing the recycle rate for gas lift (if any, the optimum cocktail of chemicals, whether some form of heating was required and whether void refilling was necessary to prevent reservoir collapse.

It is most unlikely that all this could be achieved inside six months and it would be prudent to assume a longer period. As a first-pass guess, the cost given in this report allowed nine months for a combined drilling and testing period @ US$250k per day, plus a mob/ demo of US$7 million each way from SE Asia.

Also required are two ocean going support vessels @ US$50k per day – one remaining permanently on location for support, while the other ships supplies as required from either Wellington or Napier. Mob/demob from SE Asia is approximately US$1 million each way for each vessel.

The cost of supplying chemicals is assumed to be included in the day rate. Methanol and glycol are not particularly expensive and can be delivered by service vessel. Crew change would be by helicopter.

It is possible that a less expensive specialist seismic testing/core sampling ship might prove to be suitable for the test period, but evaluation of such options and hardening-up of testing costs is outside the scope of this preliminary Report.

Development Phase

The overall field development for both the 10PJ and 150PJ case is shown in the schematics attached as Appendix 6.

It is envisaged that a single offshore gathering station will be required to collect and clean-up gas from a series of clusters of subsea wells.

For the 10PJ case, a single cluster of 6 wells is envisaged, while for the 150PJ case, and additional 4 clusters would be needed.

Located on the processing facility would be gas lift and export compressors.

Different compressor sizes are required to process the gas produced under each scenario, but it has been assumed that all machines for both scenarios would be need to be installed at the outset.

This is because of the cost of offshore construction in New Zealand is governed by the mob/ demob costs of work barges. Unless packages can be broken down into components small enough to be handled by the installed platform crane, a large work barge would have to be mobilised.

Quite apart from the difficulty of getting a barge into such a remote location, the cost of mob/ demob alone can easily exceed US25 million before any work is down.

With such economics, pre-investment in process plant can be justified, and determining the best option is a matter for further study.

Also required are a 20” pipeline to shore, a landfall receiving station and cross-country pipelines to connect to the NZ gas grid.

For the 10 PJ case, a 8” line could connect to the existing 8” grid serving Hawkes Bay

For the 150PJ case, a 24" line would need to be run to Wellington, and in addition, upgrading of the line north to Hawera would be required.

A schematic of the gas grid is appended, and it will be noted that the 8" line from Taranaki to Wellington is partly duplicated with 12" loops. Time did not allow us to define exactly what would be needed to upgrade the lower NI grid. It has been assumed that another 100km of 12" would be needed, but this assumption requires checking.

3. BASIC PROCESS DESCRIPTION

Process sketches for both offshore facilities and at the landfall receiving station are given in Appendix 7.

The basic process is to reduce the pressure in each well by removing gas and liquid, thus causing more hydrate to dissociate into gas and free water. This process will be enhanced by addition of chemicals. For conventional offshore hydrate control, glycol and methanol are used along with other speciality chemicals. Without studying what mix of chemicals is appropriate, it has been assumed that some mix of chemicals will be needed, and typical handing facilities have been allowed for.

For every 1m3 of hydrate that dissociates, it releases160-180m3 of gas and 0.9m3 of water.

To remove the produced water, a gas slip stream is recycled as “gas-lift”.

Process equipment located on the TLP are a water/ gas separator, water treatment plant, chemical storage and injection facilities, together with gas-lift and export compressors.

While water treatment and clean up is required before produced water can be discharged overboard, it has been assumed that rather than clean-up chemicals offshore, spent chemicals are better sent to the onshore receiving station for processing.

A “piggy back” line to re-supply the offshore facility is envisaged - similar that that employed at Pohokura – offshore Taranaki.

Offshore utilities required are power generation, service air, fuel gas clean-up and supply, fire-pumps, together with facilities associated with a minimum manned platform.

Given the relative simplicity of the process, it expected that the offshore operation would be unmanned and controlled from shore.

Some permanent offshore accommodation will be required for over-nighting and maintenance visits.

Topsides costs include for all the above, along with cranes, a boat-landing, helli-deck and life boats.

4. BASIC SUBSEA WELL AND PIPING LAYOUT

The proposed layout of the subsea wells for both the 10PJ and 150 PJ cases is based on that suggested in the Hancock report and shown in Appendix 6.

For 10PJ it is assumed that a single cluster of 6 wells will suffice.

For 150PJ an additional four clusters of 6 wells would be required.

Each cluster of wells would be deviated from a single subsea wellhead/ PLEM – pipe line end manifold.

Each well would be connected to both gas lift lines and production gas lines.

Chemical injection has been assumed to be into the gas lift manifold on the TLP, but an alternative to this would be to run chemicals directly into the wells via the umbilical cable used to control the valves on the subsea wellhead. Umbilical cables can be designed to accommodate power and control cables as well as hydraulic tubing and multiple chemical injection lines.

Detailed consideration of such matters is beyond the scope of the preliminary study.

5. CHOICE OF PRODUCTION "PLATFORM"

With water 1000m deep, conventional offshore jacket supported structures – like Maui for example - are out of the question.

There are three potential proven solutions that could be employed – a tension leg platform (TLP), a floating production unit (FPU) - which is basically a moored, converted tanker – or a SPAR.

The last two employ similar types of "spider catenary" moorings, and while they are less stable than a TLP, they have the advantage of being more easily relocated at a later date.

A TLP is a floating square or circular hull attached to the sea floor by vertical tendons. Being jacked down below its natural level of buoyancy, it exerts an upward force on the tendons, which thus constrain sideways motion. A TLP is like a reed waving in a pond.

As there isn't a great difference in cost between all three, a decision was made to only cost out a TLP.

The diagrams attached in the appendices contain a lot of technical/ project data on worldwide applications of SPARS and TLPs.

One matter where gas hydrates differ from conventional gas well is in the area of subsidence and the effect this might have on ground stability. To avoid problems with pile anchoring, it has been assumed that the TLP (or any other type of processing platform) would need to be located a safe distance away from the nearest well.

6. DEVELOPMENT SCHEDULE

The main components of the development programme are:

- conceptual and FEED design,
- rig mobilisation, and drilling of the clusters of subsea wells,
- fabrication, transportation and installation of the central offshore processing facility.
- Hook up and offshore commissioning
- Construction and commissioning of land fall receiving facilities
- Consenting and construction of cross country pipelines

Given the similarity of the technology with other conventional offshore projects utilising TLPs, FPUs or SPARs, the timescales given in Appendix 5 provide a good indication of expected project timing.

For the processing equipment envisaged for, a small to mid-sized TLP or SPAR would be needed.

Hancock proposed using a FPU (floating production unit) which is also practical and feasible.

Considerably more study is required to make a selection between these alternates.

Appendix 5 tabulates hard data for SPARS and TLPs from around the world.

For a small to medium TLPs- such as is envisaged for this project- a 30 month study time is a typical time before a final investment decision can be made.

Total project time from discovery till first gas is about 70 months.

Appendix 1
Capex

by : jdeb 05/03/2009

Exchange Rates	
Australian Dollars	AU 0.81
New Zealand Dollars	NZ 1.00
Pounds Sterling	STG 0.35
US Dollars	US 0.51

TRANSFIELD WORLEY

GAS HYDRATES CAPITAL COST ESTIMATE

OVERALL SUMMARY

Type 1 (-40% / + 40%)

NZ$ millions(Year 2009 Real Terms)

Project No. 501102

Description	OWNER'S COSTS	Land and Existing Assets	Equipment	Bulks	Onshore Fabrication / Construction	Mob/ Demob	Transport	Offshore Testing	Hook-up	Design (incl. Cert'n)	Project Managem't	Sub-Total	EPC Contractors Margin %	EPC Contractors Margin Amount	BASE ESTIMATE	Contingency %	Contingency Amount	ESTIMATE TOTAL	Notes
APPRAISAL & TESTING	10	0	0	0	0	0	0	0	0		0	10	0.0%	0	10		2	12	
Appraisal for test programme	10	0	0	0	0	0	0	0	0		0	10	0.0%	0	10	20.0%	2	12	
PM & Eng	10											10	0.0%	0	10	20.0%	2	12	
DRILLING & TESTING	0	0	5	14	6	35	0	198	0		0	258	0	0	258	20.2%	52	310	
Development Wells	0	0	5	14	6	35	0	198	0		0	258	0	0	258	20.2%	52	310	
'Offshore wells (2 off)				10				10			0	20	0.0%	0	20	20.0%	4	24	}
9 mth test @ US250k/ day + 2*US$50k/d			5	4	6			188				203	0.0%	0	203	20.0%	41	244	
Mob/ demob (rig & 2 off service vessels)						35						35	0.0%	0	35	20.0%	7	42	
TOTAL TESTING PHASE	10	0	5	14	6	35	0	198	0	0	0	268			268		54	322	

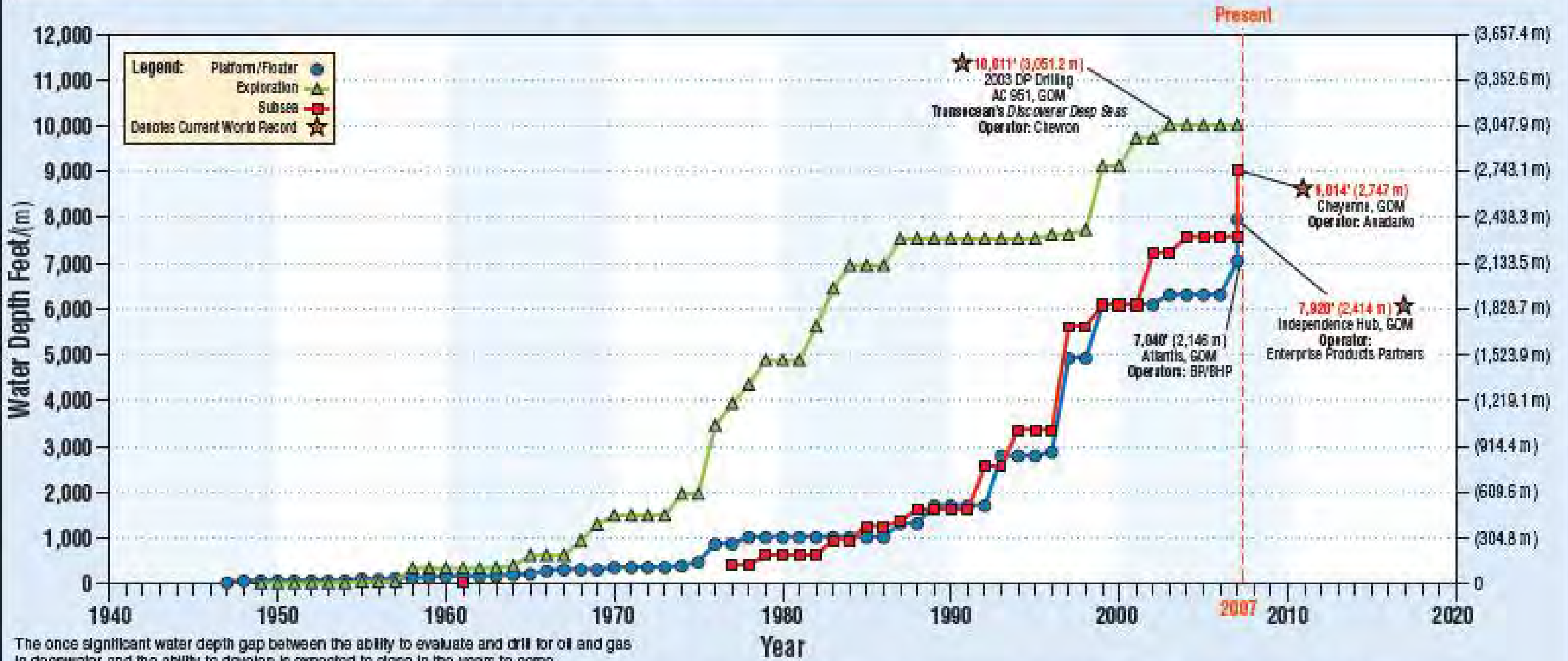
Description	OWNER'S COSTS	Land and Existing Assets	Equipment	Bulks	Onshore Fabrication / Construction	Mob/ Demob	Transport	Offshore Installation	Hook-up	Design (incl. Cert'n)	Project Managem't	Sub-Total	EPC Contractors Margin %	EPC Contractors Margin Amount	BASE ESTIMATE	Contingency %	Contingency Amount	ESTIMATE TOTAL	Notes
APPRAISAL & DEVELOPMENT: 10PJ	60	0	0	0	0	0	0	0	0		0	60	0.0%	0	60	0.0%	6	66	
Appraisal & development	60	0	0	0	0	0	0	0	0		0	60	0.0%	0	60	10.0%	6	66	
67 PM, Eng, QC & admin	40											40	0.0%	0	40	10.0%	4	44	
25 Operations & commisssioning	15											15	0.0%	0	15	10.0%	1	16	
8 Insurance	5											5	0.0%	0	5	10.0%	1	6	
DRILLING - 10PJ phase	10	0	0	54	0	27	0	306	0		0	397	0	0	397	19.9%	79	476	
Development Wells	0	0	0	54	0	27	0	306	0		0	387	0	0	387	19.9%	77	464	
Well Engineering & subsurface studies	10											10	0.0%	0	10	20.0%	2	12	
'Offshore wells				54				306			0	360	0.0%	0	360	20.0%	72	432	}
Mob/ demob						27						27	0.0%	0	27	20.0%	5	32	
OFFSHORE FACILITIES - 10PJ phase	9	0	23	181	43	8	8	199	0	26	46	543	10.1%	55	598	19.4%	116	714	
TLP	9	0	23	64	43	8	8	34	0	26	19	234	1.3%	3	258	19.8%	51	309	
TLP hull				12	14		1.7					27	10.0%	3	30	20.0%	6	36	
TLP deck				1	6							7	10.0%	1	8	20.0%	2	10	
Process Topsides	9		21	23	11	8	4	34		26	19	156	10.0%	16	172	20.0%	34	206	
Tendons				28	13		2					42	10.0%	4	46.1	20.0%	9	55.1	
Marine Access craft			1.5									2	10.0%	0	1.5	20.0%	0	1.5	
Subsea Pipelines & Umbilicals	0	0	0	117	0	0	0	166	0	0	27	310	10.0%	31	340.9		65	405.9	
Subsea gathering lines & umbilicals				46				56			11	113	10.0%	11	123.6	20.0%	25	148.6	
Export pipeline to shore				71				80			16	167	10.0%	17	184.3	20.0%	37	221.3	
Pipeline stabilisation & rock dumping								30				30	10.0%	3	33.0	10.0%	3	36.0	
ONSHORE FACILITIES: 10PJ	0	0	10	38	36	0	0	0	0	4	5	94	0	4	98.0	8.2%	8	106.0	
Receiving station	0	0	10	6	8	0	0	0	0	3	3	30	13.4%	4	33.8	10.0%	4	37.8	
Site Development					1.2					0.1	0.1	1.3	10.0%	0	1.3	10.0%	0	1.3	
Landfall treatment Plant			6.5	4.3	2.7					1.5	1.4	16	10.0%	2	18.3	10.0%	2	20.3	
Sales Gas Export			2.8	1.1	1.3					0.4	1.1	7	10.0%	1	7.6	10.0%	1	8.6	
Utilities & Infrastructure: 10PJ			0.9	1.1	2.3					0.6	0.5	5	10.0%	1	6.4	10.0%	1	7.4	
Onshore pipelines	0	0	0	32	29	0	0	0	0	2	2	64	0.0%	0	64.3	6.2%	4	68.3	
Pipeline easement/ acquisition					5					0.2	0.5	5	0.0%	0	5.5	0.0%	0	5.5	
1st Gas Pipeline to National grid			0.1	32	24					1	2	59	0.0%	0	58.8	7.0%	4	62.8	
TOTAL FACILITIES	9	0	33	219	80	8	8	199	0	31	51	638	9.3%	59	696.5	17.8%	124	820.5	
TOTAL DRILLING & MANAGEMENT	70	0	0	54	0	27	0	306	0	0	0	457			456.8	18.6%	85	541.8	
TOTAL 10PJ PHASE	78	0	33	273	80	35	8	505	0	31	51	1,094		0	1,153	18.1%	209	1,362	

ADDERS FOR 150PJ

Description	OWNER'S COSTS	Land and Existing Assets	Equipment	Bulks	Onshore Fabrication / Construction	Mob/ Demob	Transport	Offshore Installation	Hook-up	Design (incl. Cert'n)	Project Managem't	Sub-Total	EPC Contractors Margin %	EPC Contractors Margin Amount	BASE ESTIMATE	Contingency %	Contingency Amount	ESTIMATE TOTAL	Notes
APPRAISAL AND DEVELOPMENT	120	0	0	0	0	0	0	0	0		0	120	0.0%	0	120	0.0%	12	132	
Appraisal & development	120	0	0	0	0	0	0	0	0		0	120	0.0%	0	120	10.0%	12	132	
PM, Eng, QC & admin	80											80	0.0%	0	80	10.0%	8	88	
Operations & commisssioning	30											30	0.0%	0	30	10.0%	3	33	
Insurance	10											10	0.0%	0	10	10.0%	1	11	
DRILLING - 150PJ phase	30	0	0	216	0	27	0	1,224	0		0	1,497	0	0	1,497	20.0%	299	1,796	
Development Wells	30	0	0	216	0	27	0	1,224	0	0	0	1,467	0	0	1,467	20.0%	293	1,760	
Well Engineering & subsurface studies	30											30	0.0%	0	30	20.0%	6	36	
Offshore wells				216				1,224				1,440	0.0%	0	1,440	20.0%	288	1,728	}
Mob/ demob						27						27	0.0%	0	27	20.0%	5	32	
OFFSHORE FACILITIES - 150PJ phase	0	0	0	71	0	0	0	80	0	0	16	167	10.2%	17	184	20.1%	37	221	
Subsea Pipelines & Umbilicals	0	0	0	71	0	0	0	80	0	0	16	167	10.2%	17	184.3		37	221.3	
Subsea gathering lines & umbilicals				71				80			16	167	10.0%	17	184.3	20.0%	37	221.3	
ONSHORE FACILITIES - 150PJ phase	0	0	7	151	122	0.0	0.0	0	0	8	10	297	0	2	299.3	7.0%	21	320.3	
Receiving station	0	0	7	3	3	0.0	0.0	0	0	1	2	16	12.5%	2	18.0	10.0%	2	20.0	
Landfall treatment Plant			3	1	1					0.4	0.5	6	10.0%	1	7.0	10.0%	1	8.0	
Sales Gas Export			3	1	1					0.4	1.1	7	10.0%	1	7.6	10.0%	1	8.6	
Utilities & Infrastructure: 150PJ			1	1	1					0.4	0.3	3	10.0%	0	3.3	10.0%	0	3.3	
Onshore pipelines	0	0	0	148	118	0.0	0.0	0	0	7	8	281	0.0%	0	281.3	6.8%	19	300.3	
Pipeline easement/ acquisition					10					0.5	1.0	11	0.0%	0	11.2	0.0%	0	11.2	
2nd Gas Pipeline to National grid			0.1	148	109					7	7	270	0.0%	0	270.1	7.0%	19	289.1	
TOTAL FACILITIES	0	0	7	222	122	0.0	0.0	80	0	8	26	465	4.1%	19	483.6	12.0%	58	541.6	
TOTAL DRILLING & MANAGEMENT	150	0	0	216	0	27	0	1,224	0	0	0	1,617			1,953.8	19.7%	384	2,337.8	
TOTAL ADDRS for 150PJ PHASE	150	0	7	438	122	27	0	1,304	0	8	26	2,081		0	2,437	18.1%	442	2,879	

Appendix 2
Overview Diagram of Worldwide Deepwater Drilling Capability

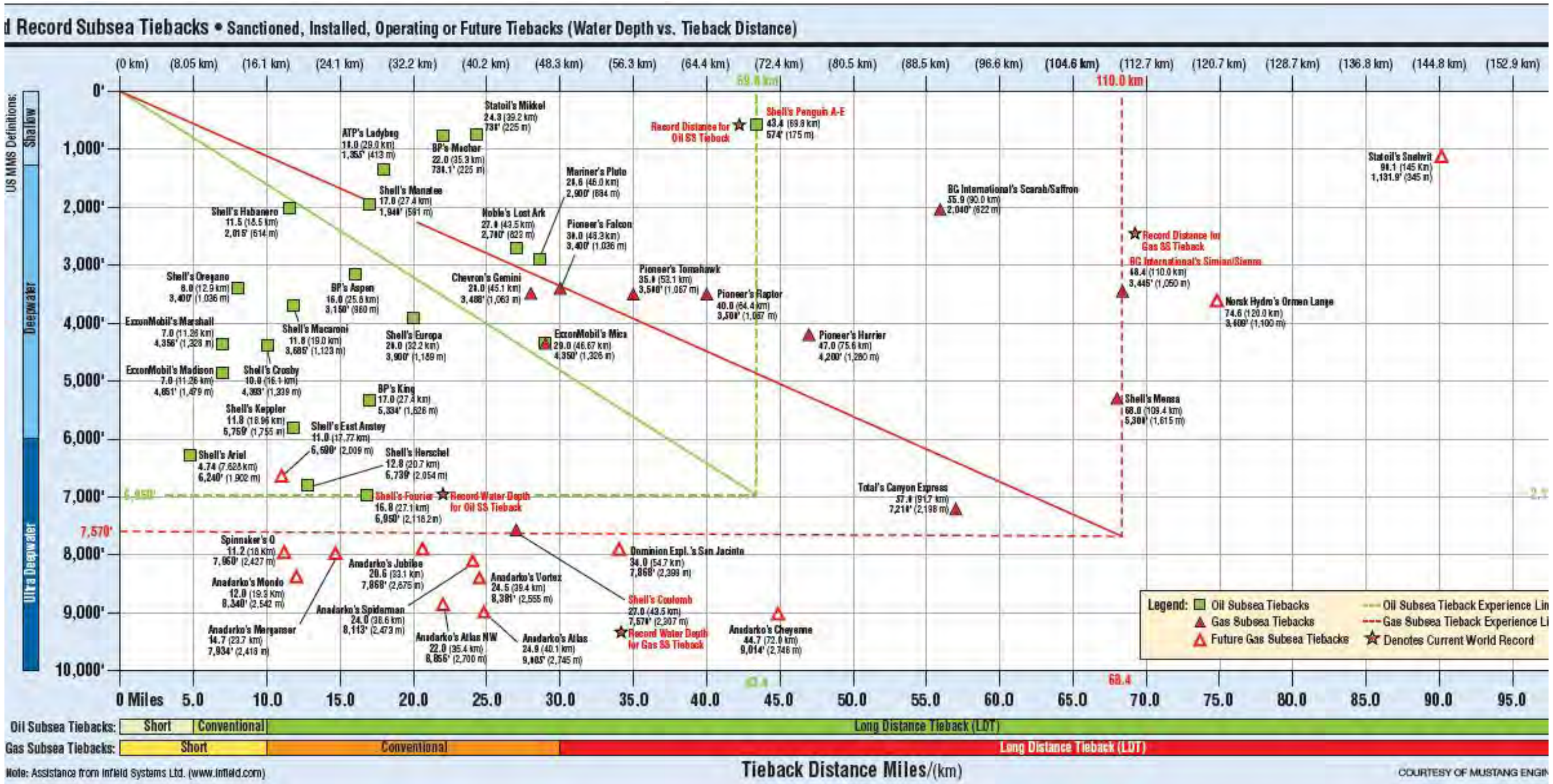
Worldwide Progression of Water Depth Capabilities for Drilling & Production



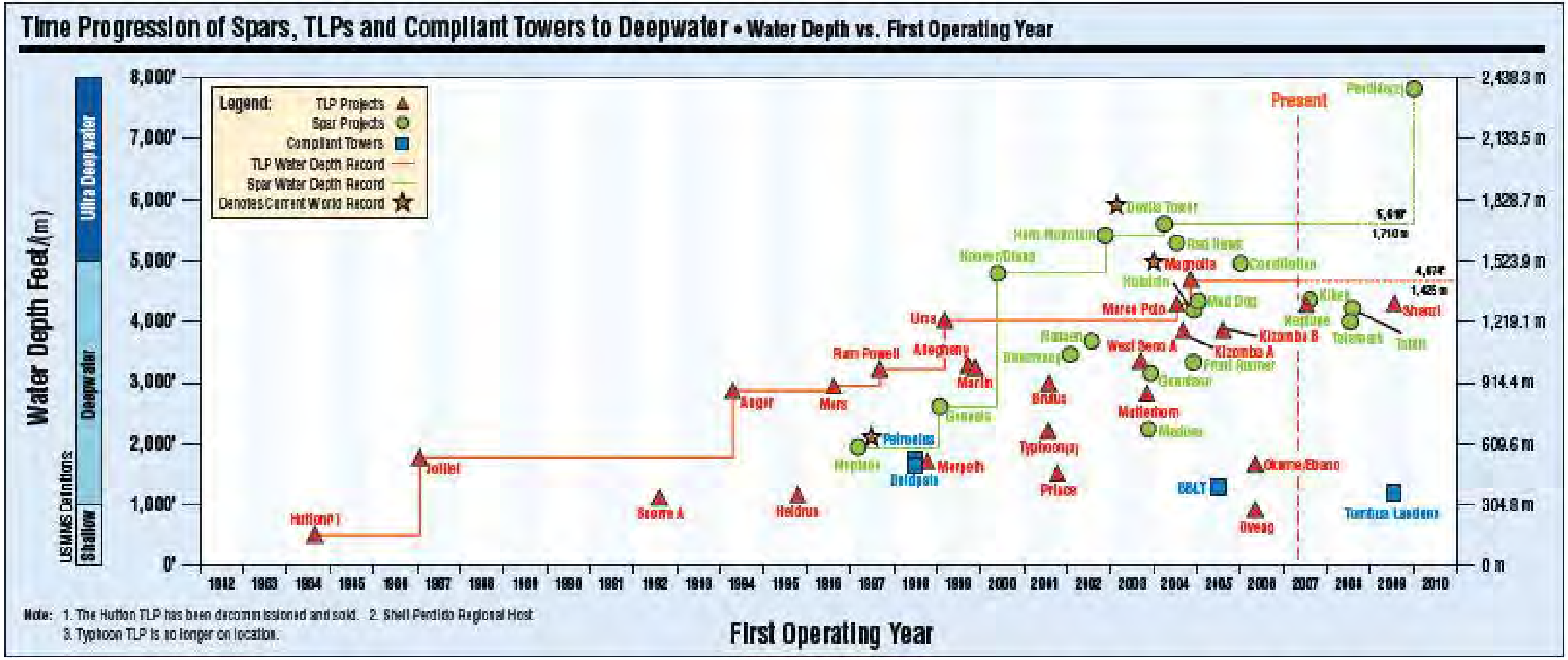
The once significant water depth gap between the ability to evaluate and drill for oil and gas in deepwater and the ability to develop is expected to close in the years to come.

SOURCES: "RACE ON FOR DEEPWATER ACREAGE, 3,500-METER DEPTH CAPABILITY," *OFFSHORE MAGAZINE* OCTOBER 1998, PAGE 40-41, 152, 156. *UPSTREAM MAGAZINE*, INTERNET SEARCHES, COMPANY LITERATURE, AND *OFFSHORE MAGAZINE* (UPDATED THROUGH MARCH, 2008); DRILLING WD RECORDS SOURCE: TRANSOCEAN.

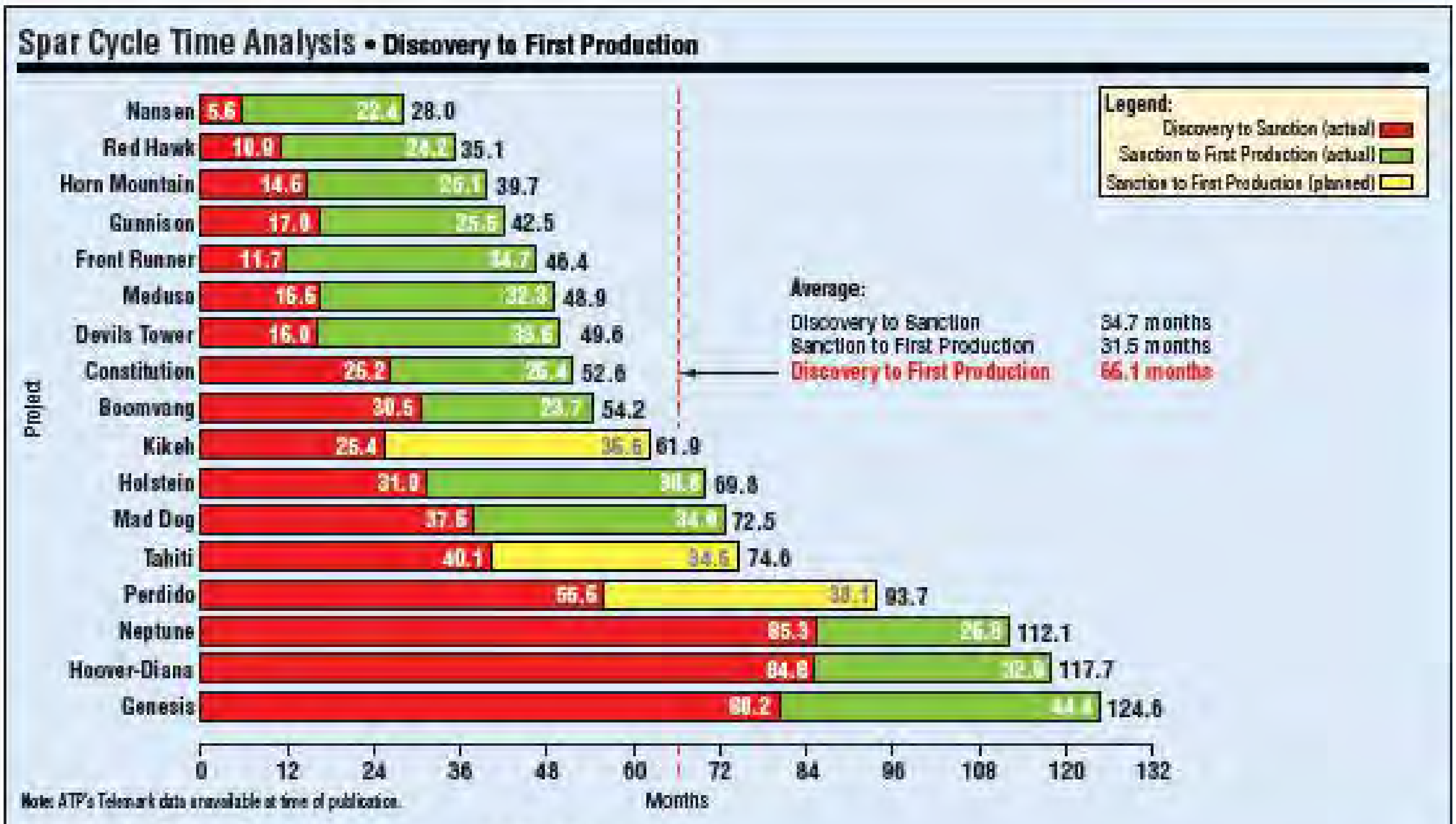
Appendix 3
Subsea Tie Back Distances

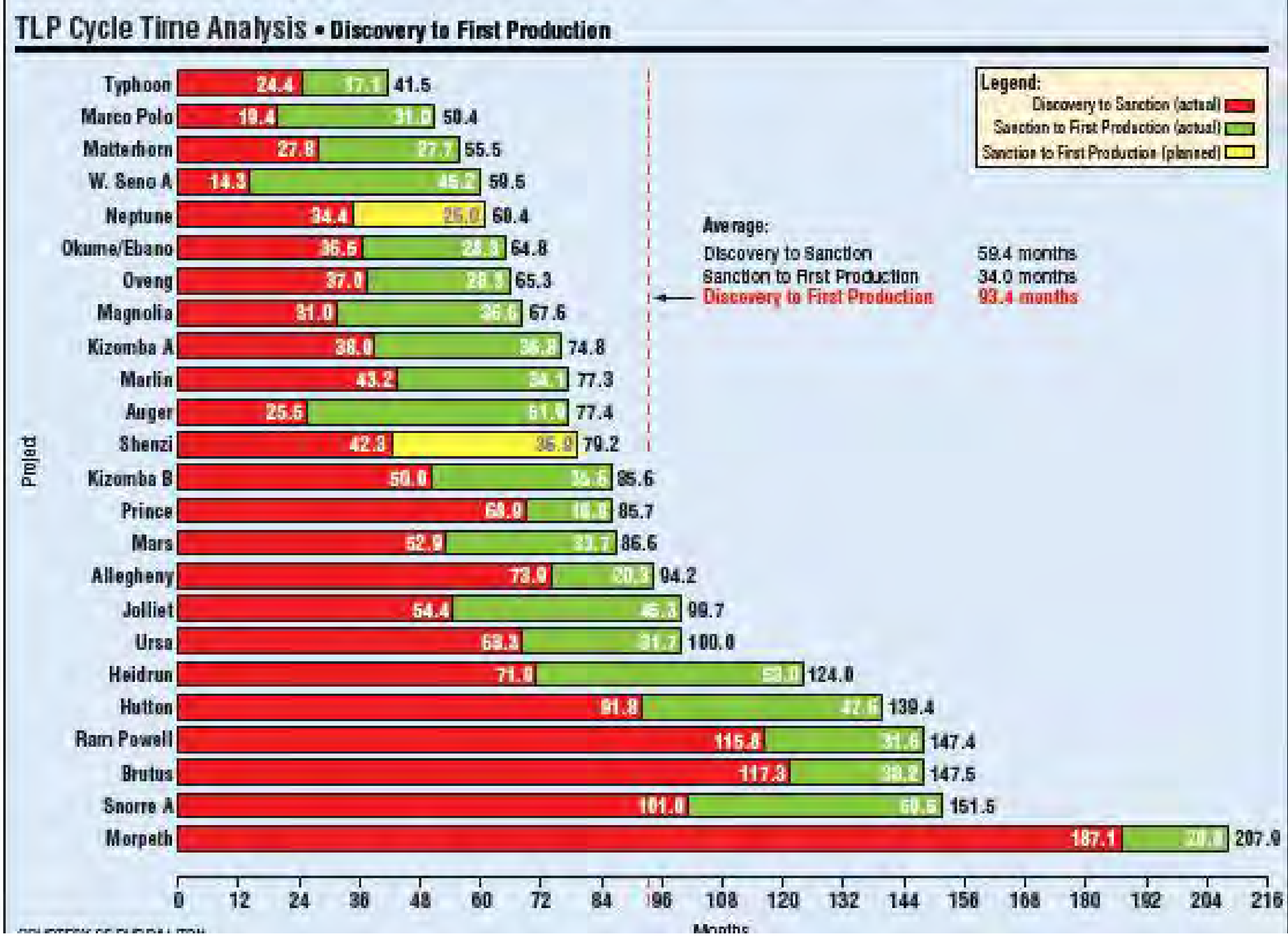

d Record Subsea Tiebacks • Sanctioned, Installed, Operating or Future Tiebacks (Water Depth vs. Tieback Distance)
US MMS Definitions:
Shallow
Deepwater
Ultra Deepwater
0'
1,000'
2,000'
3,000'
4,000'
5,000'
6,000'
7,000'
8,000'
9,000'
10,000'
6,950'
7,570'
69.8 km
110.0 km
43.4
68.4
0 Miles
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0
45.0
50.0
55.0
60.0
65.0
70.0
75.0
80.0
85.0
90.0
95.0
Legend:
Oil Subsea Tiebacks
Gas Subsea Tiebacks
Future Gas Subsea Tiebacks
Oil Subsea Tieback Experience Lin
Gas Subsea Tieback Experience Li
Denotes Current World Record
Oil Subsea Tiebacks:
Short
Conventional
Long Distance Tieback (LDT)
Gas Subsea Tiebacks:
Short
Conventional
Long Distance Tieback (LDT)
Note: Assistance from Infield Systems Ltd. (www.infield.com)
Tieback Distance Miles/(km)
COURTESY OF MUSTANG ENGIN

Appendix 4
Time Progression of Spars, TLPs and Compliant Towers in Deep Water

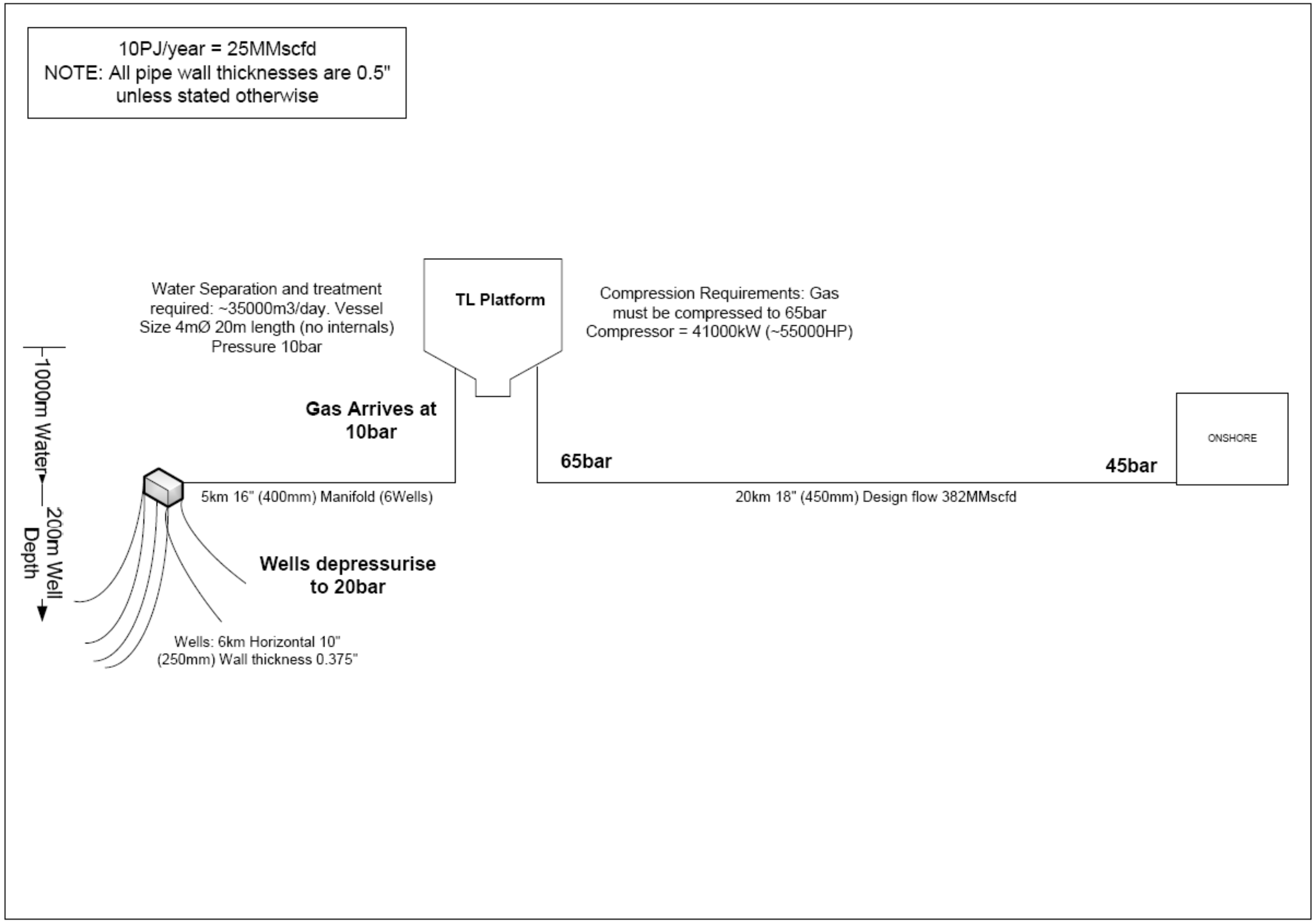

Time Progression of Spars, TLPs and Compliant Towers to Deepwater • Water Depth vs. First Operating Year
Legend:
TLP Projects
Spar Projects
Compliant Towers
TLP Water Depth Record
Spar Water Depth Record
Denotes Current World Record
Water Depth Feet/(m)
USMMS Definitions
Ultra Deepwater
Deepwater
Shallow
8,000'
7,000'
6,000'
5,000'
4,000'
3,000'
2,000'
1,000'
0'
2,438.3 m
2,133.5 m
1,828.7 m
1,523.9 m
1,219.1 m
914.4 m
609.6 m
304.8 m
0 m
Present
Hutton(1)
Jolliet
Snorre A
Heidrun
Auger
Mars
Ram Powell
Ursa
Allegheny
Marlin
Petronius
Morpeth
Genesis
Brutus
Typhoon(3)
Prince
Matterhorn
West Seno A
Kizomba A
Kizomba B
Magnolia
Marco Polo
Neptune
Shenzi
Okume/Ebano
Oveng
BBLT
Tombua Landana
First Operating Year
Note: 1. The Hutton TLP has been decommissioned and sold. 2. Shell Perdido Regional Host
3. Typhoon TLP is no longer on location.

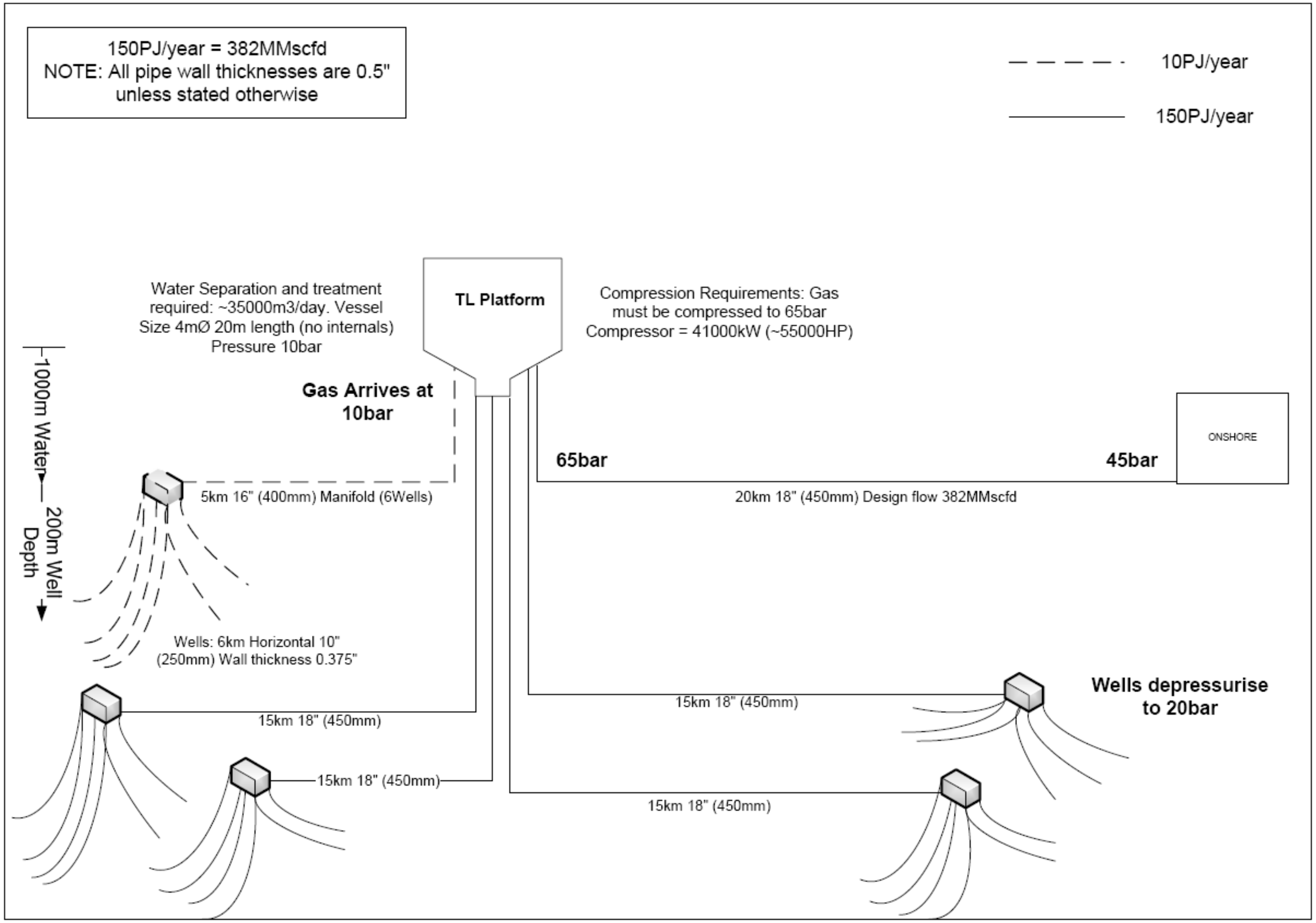
Appendix 5
SPAR & TLP Cycle Time Aanalysis (Discovery to First Gas)


Spar Cycle Time Analysis • Discovery to First Production
Legend:
Discovery to Sanction (actual)
Sanction to First Production (actual)
Sanction to First Production (planned)
Average:
Discovery to Sanction 34.7 months
Sanction to First Production 31.5 months
Discovery to First Production 66.1 months
Project
Nansen 5.6 22.4 28.0
Red Hawk 10.9 24.2 35.1
Horn Mountain 14.6 25.1 39.7
Gunnison 17.0 25.5 42.5
Front Runner 11.7 34.7 46.4
Medusa 16.6 32.3 48.9
Devils Tower 16.0 33.6 49.6
Constitution 26.2 26.4 52.6
Boomvang 30.5 23.7 54.2
Kikeh 25.4 36.5 61.9
Holstein 31.0 38.8 69.8
Mad Dog 37.5 72.5
Tahiti 40.1 34.5 74.6
Perdido 55.6 38.1 93.7
Neptune 85.3 26.8 112.1
Hoover-Diana 84.8 32.9 117.7
Genesis 80.2 44.4 124.6
0 12 24 36 48 60 72 84 96 108 120 132
Months
Note: ATP's Telemark data unavailable at time of publication.

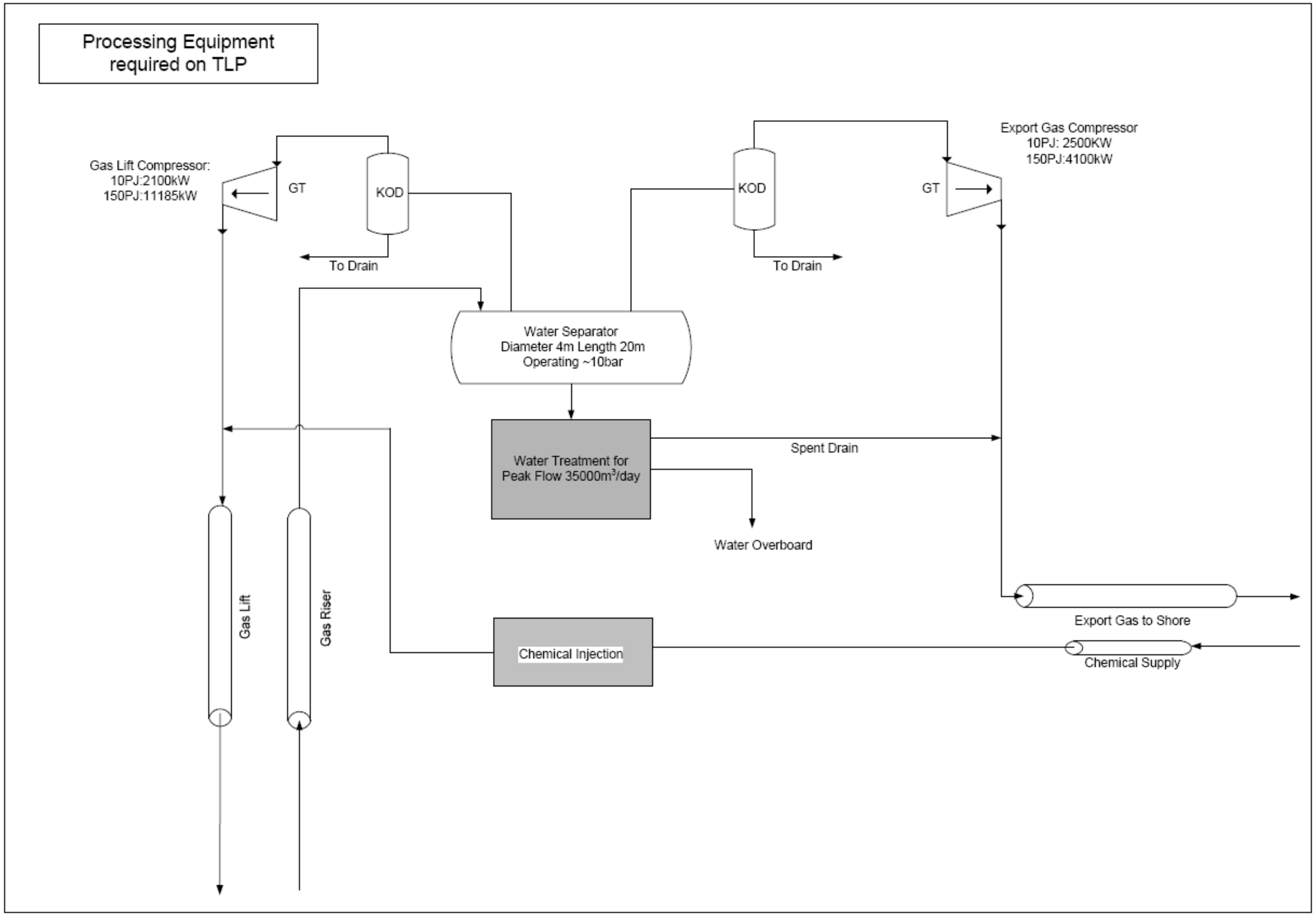

TLP Cycle Time Analysis • Discovery to First Production
Legend:
Discovery to Sanction (actual)
Sanction to First Production (actual)
Sanction to First Production (planned)
Average:
Discovery to Sanction 59.4 months
Sanction to First Production 34.0 months
Discovery to First Production 93.4 months
Project
Typhoon 24.4 17.1 41.5
Marco Polo 19.4 31.0 50.4
Matterhorn 27.8 27.7 55.5
W. Seno A 14.3 45.2 59.5
Neptune 34.4 26.0 60.4
Okume/Ebano 36.5 28.3 64.8
Oveng 37.0 28.3 65.3
Magnolia 31.0 36.6 67.6
Kizomba A 38.0 36.8 74.8
Marlin 43.2 34.1 77.3
Auger 25.5 51.9 77.4
Shenzi 42.3 36.9 79.2
Kizomba B 50.0 35.6 85.6
Prince 68.9 16.8 85.7
Mars 52.9 33.7 86.6
Allegheny 73.9 20.3 94.2
Jolliet 54.4 45.3 99.7
Ursa 68.3 31.7 100.0
Heidrun 71.0 53.0 124.0
Hutton 91.8 47.6 139.4
Ram Powell 115.8 31.6 147.4
Brutus 117.3 30.2 147.5
Snorre A 101.0 50.5 151.5
Morpeth 187.1 20.8 207.9
0 12 24 36 48 60 72 84 96 108 120 132 144 156 168 180 192 204 216

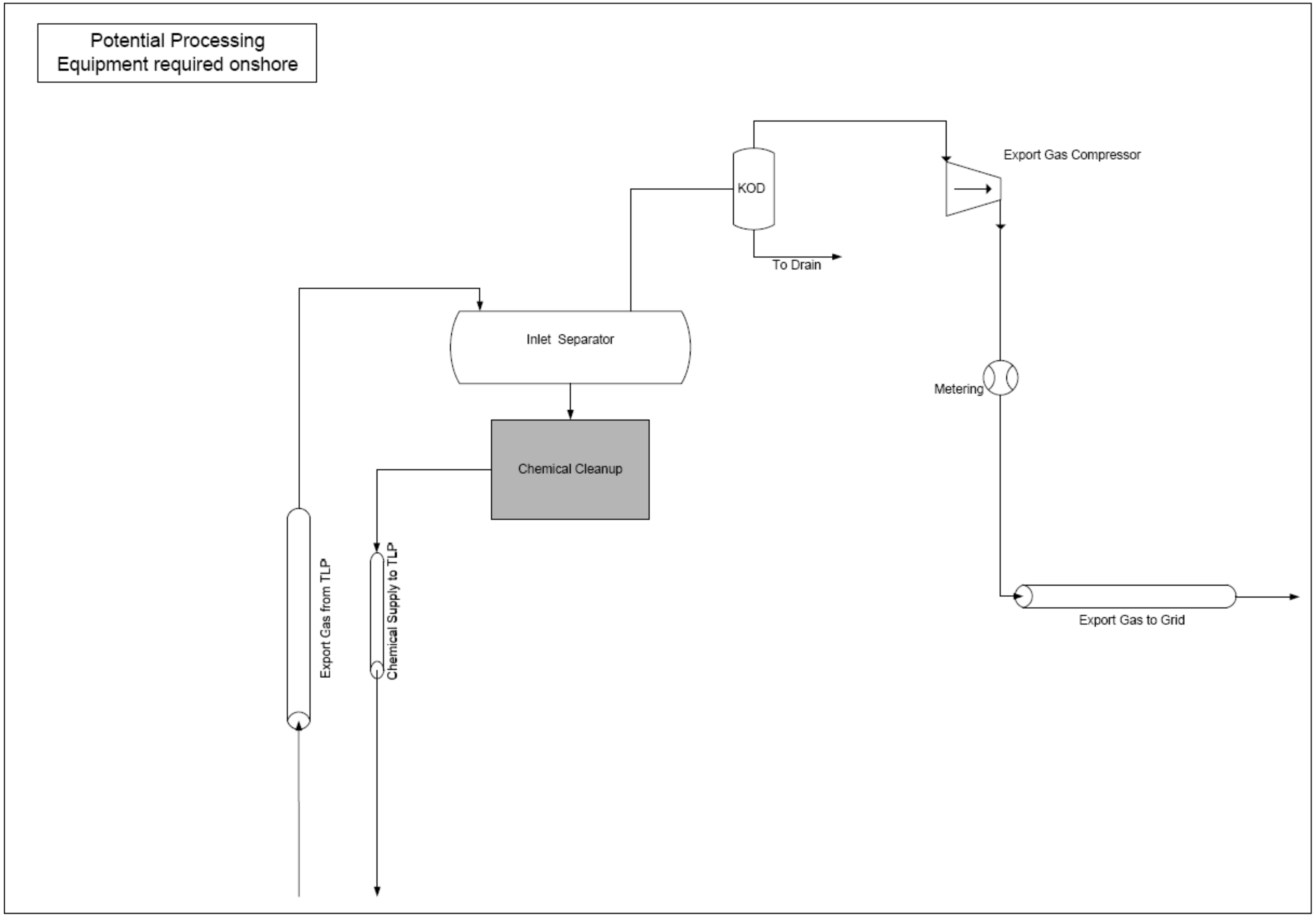
Appendix 6
Development Schematics


10PJ/year = 25MMscfd
NOTE: All pipe wall thicknesses are 0.5" unless stated otherwise
Water Separation and treatment required: ~35000m3/day. Vessel Size 4mØ 20m length (no internals) Pressure 10bar
TL Platform
Compression Requirements: Gas must be compressed to 65bar Compressor = 41000kW (~55000HP)
1000m Water
200m Well Depth
Gas Arrives at 10bar
65bar
45bar
ONSHORE
5km 16" (400mm) Manifold (6Wells)
20km 18" (450mm) Design flow 382MMscfd
Wells depressurise to 20bar
Wells: 6km Horizontal 10" (250mm) Wall thickness 0.375"

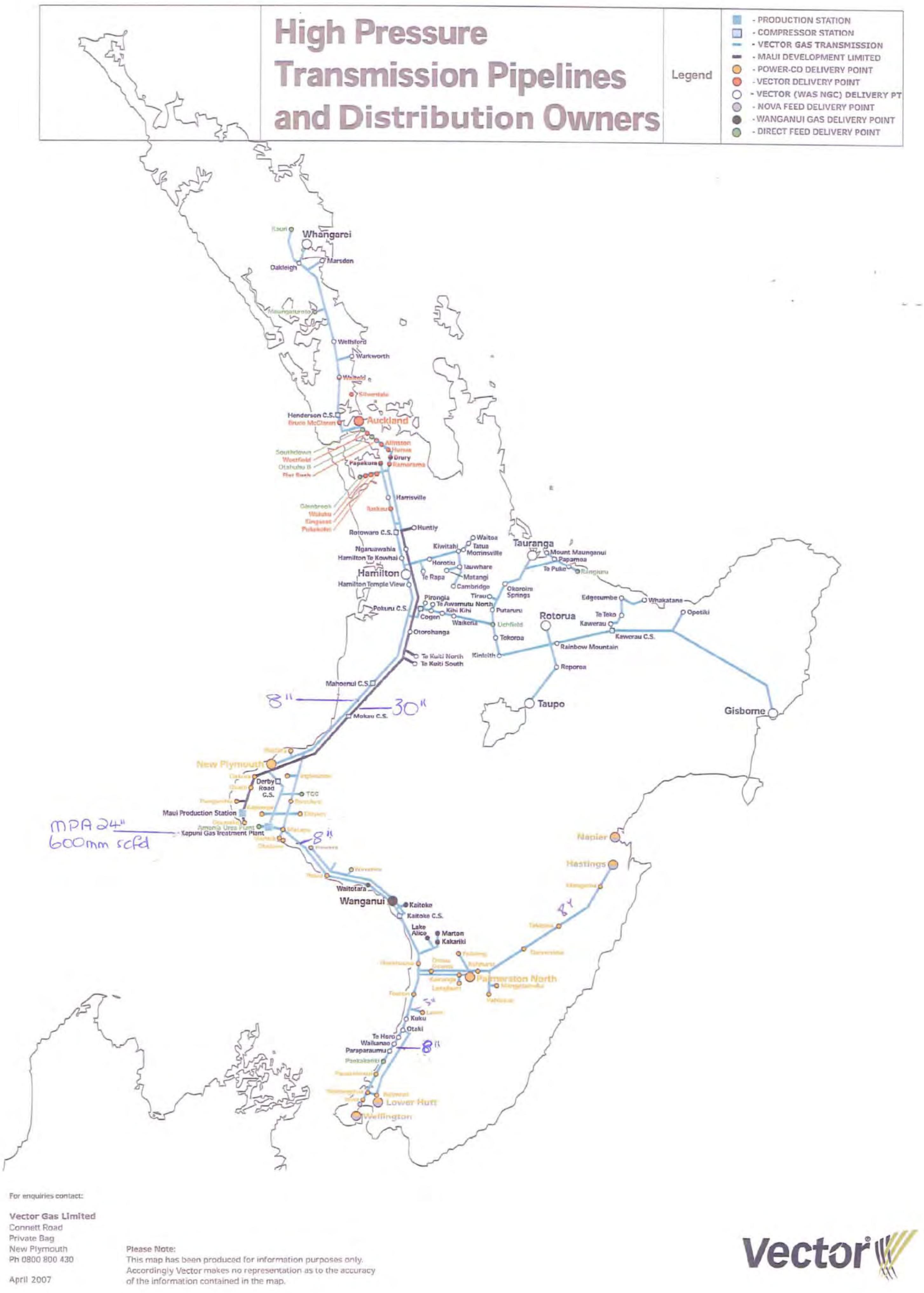

150PJ/year = 382MMscfd
NOTE: All pipe wall thicknesses are 0.5" unless stated otherwise
10PJ/year
150PJ/year
Water Separation and treatment required: ~35000m3/day. Vessel Size 4mØ 20m length (no internals) Pressure 10bar
TL Platform
Compression Requirements: Gas must be compressed to 65bar Compressor = 41000kW (~55000HP)
1000m Water
200m Well Depth
Gas Arrives at 10bar
65bar
45bar
ONSHORE
5km 16" (400mm) Manifold (6Wells)
20km 18" (450mm) Design flow 382MMscfd
Wells: 6km Horizontal 10" (250mm) Wall thickness 0.375"
15km 18" (450mm)
15km 18" (450mm)
Wells depressurise to 20bar
15km 18" (450mm)
15km 18" (450mm)

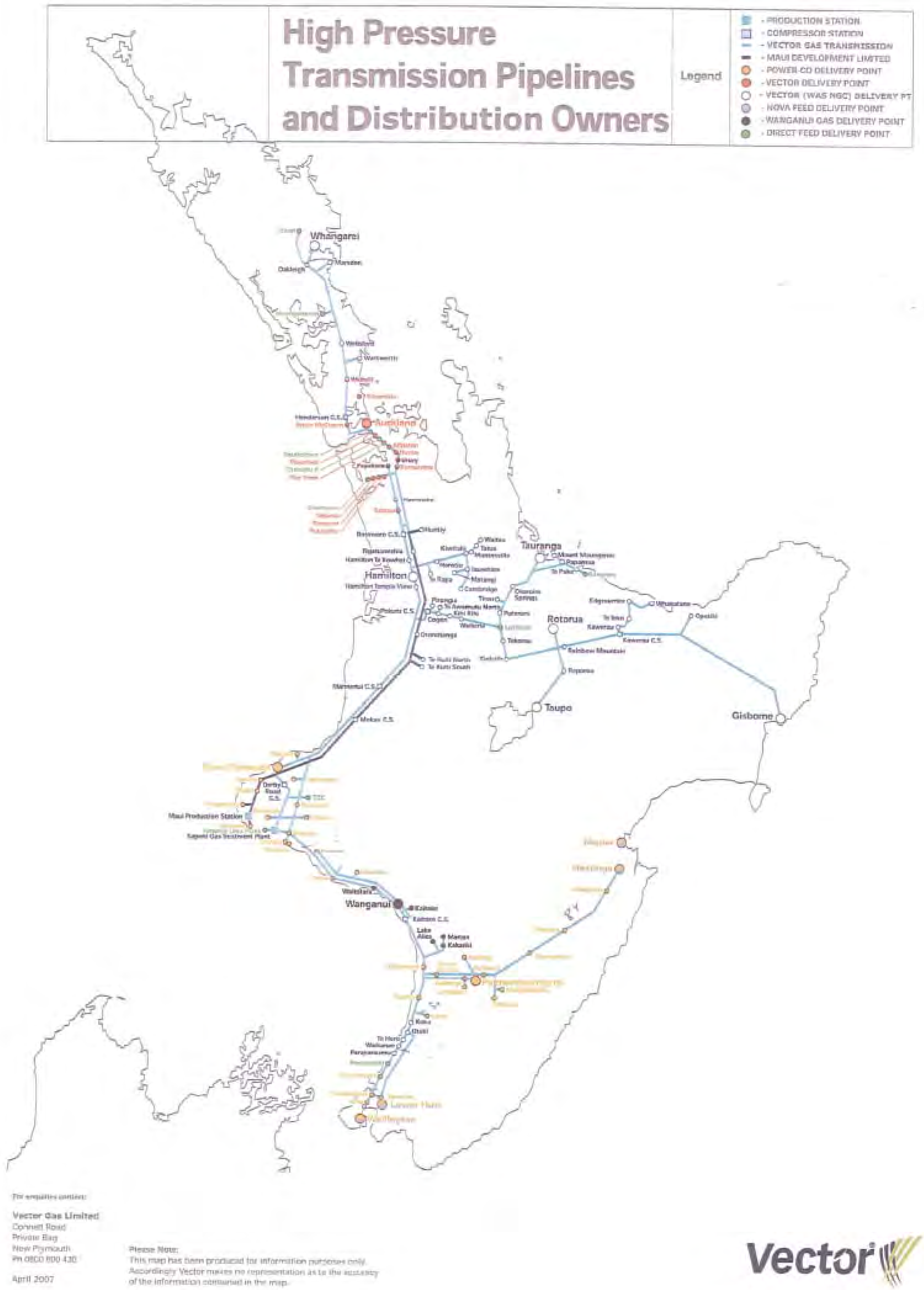
Appendix 7
Process Schematics


Processing Equipment required on TLP
Gas Lift Compressor:
10PJ:2100kW
150PJ:11185kW
GT
KOD
To Drain
KOD
To Drain
GT
Export Gas Compressor
10PJ: 2500KW
150PJ:4100kW
Water Separator
Diameter 4m Length 20m
Operating ~10bar
Water Treatment for
Peak Flow 35000m³/day
Spent Drain
Water Overboard
Gas Lift
Gas Riser
Export Gas to Shore
Chemical Injection
Chemical Supply


Potential Processing
Equipment required onshore
Export Gas Compressor
KOD
To Drain
Inlet Separator
Metering
Chemical Cleanup
Export Gas from TLP
Chemical Supply to TLP
Export Gas to Grid

Appendix 8
Vector Gas Grid


High Pressure Transmission Pipelines and Distribution Owners
Legend
- PRODUCTION STATION
- COMPRESSOR STATION
- VECTOR GAS TRANSMISSION
- MAUI DEVELOPMENT LIMITED
- POWER-CO DELIVERY POINT
- VECTOR DELIVERY POINT
- VECTOR (WAS NGC) DELIVERY PT
- NOVA FEED DELIVERY POINT
- WANGANUI GAS DELIVERY POINT
- DIRECT FEED DELIVERY POINT
Whangarei
Auckland
Hamilton
Tauranga
Rotorua
Taupo
Gisborne
New Plymouth
Maui Production Station
Napier
Hastings
Wanganui
Palmerston North
Lower Hutt
Wellington
8"
30"
MPA 24"
600mm scfd
8"
8"
8"
For enquiries contact:
Vector Gas Limited
Connett Road
Private Bag
New Plymouth
Ph 0800 800 430
April 2007
Please Note:
This map has been produced for information purposes only.
Accordingly Vector makes no representation as to the accuracy
of the information contained in the map.
Vector


High Pressure Transmission Pipelines and Distribution Owners
Legend
- PRODUCTION STATION
- COMPRESSOR STATION
- VECTOR GAS TRANSMISSION
- MAUI DEVELOPMENT LIMITED
- POWER-CO DELIVERY POINT
- VECTOR DELIVERY POINT
- VECTOR (WAS NGC) DELIVERY PT
- NOVA FEED DELIVERY POINT
- WANGANUI GAS DELIVERY POINT
- DIRECT FEED DELIVERY POINT
Whangarei
Auckland
Hamilton
Tauranga
Rotorua
Taupo
Gisborne
Maui Production Station
Wanganui
For enquiries contact:
Vector Gas Limited
Corrnett Road
Private Bag
New Plymouth
Ph 0800 800 430
April 2007
Please Note:
This map has been produced for information purposes only.
Accordingly Vector makes no representation as to the accuracy
of the information contained in the map.
Vector

Appendix 9
Cross Country Pipelines

Approximate Pipeline Length: 90km

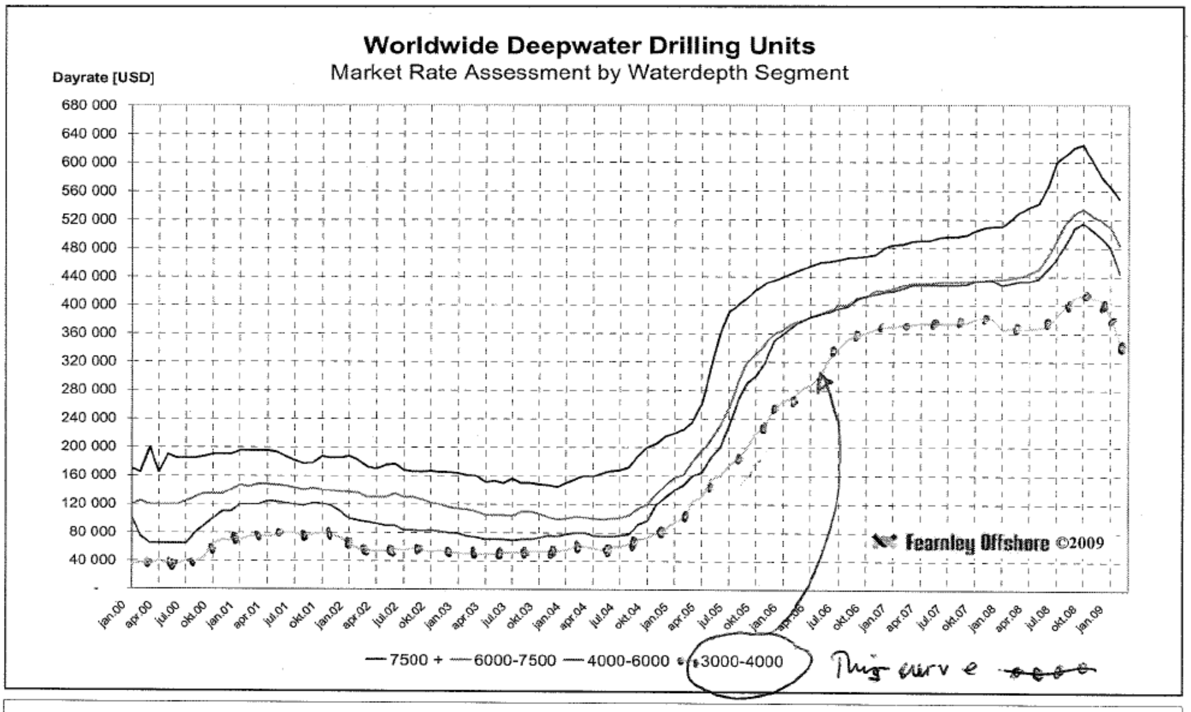
	Pipeline Tie at Lower Hut	Inlet Pressure (Bar)	Outlet Pressure at Lower Hut (Bar)	Compressor kW (HP)
10PJ - 25MMscfd	8"	80	51	760 (~1000)
150PJ - 382MMscfd	24"	80	52	11720 (~15700)

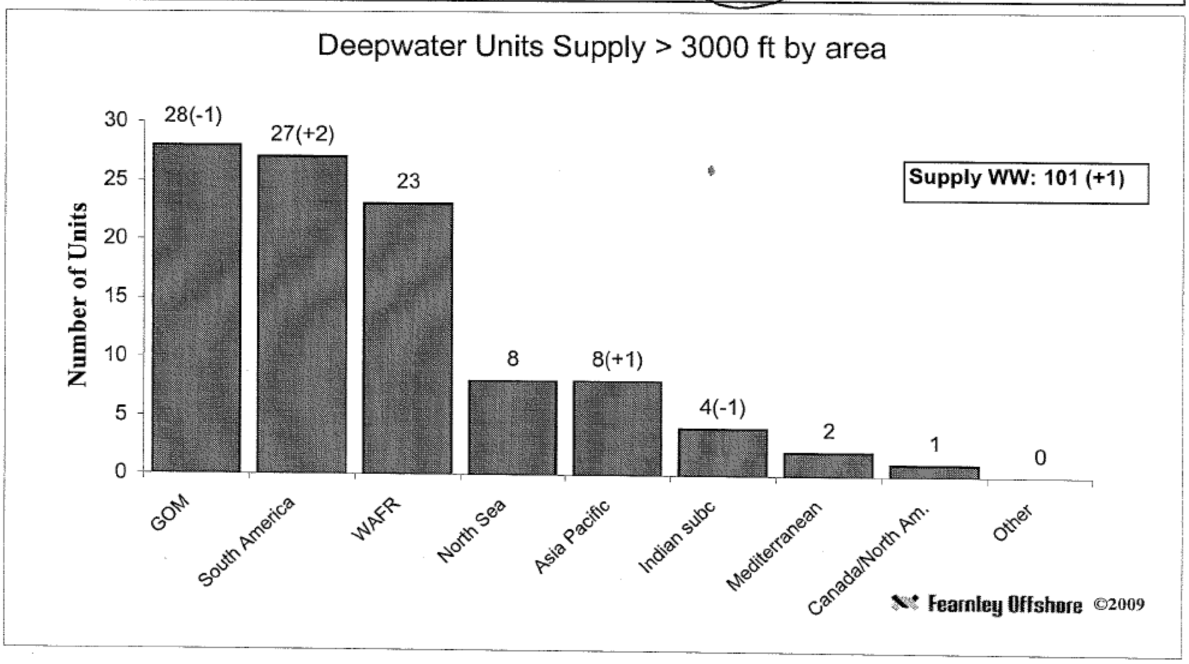
Appendix 10
Deepwater Rig Rates and Areas of Operation

Fearnley Offshore

Feb	2009	P. 6

Deepwater rates and area of operation





APPENDIX 7: Gas Hydrates Economic Analysis

Economic Analysis

The purpose of this economic analysis is to demonstrate that gas hydrate technology has the potential to become a viable alternative/ replacement for indigenous and imported fuels/ gas. Specific objectives of the analysis are to:

- Demonstrate that gas hydrates are economically competitive with alternative future sources of gas
- Demonstrate the economic benefits of government policy designed to accelerate the development of New Zealand's hydrate resource.
- Determine whether the export of methane is likely to add value to a hydrate development project

1. Methodology

A national economic cost-benefit analysis following the methodology outlined in Treasury's Cost Benefit Primer is used as the basis for assessing the benefits or other wise of developing the hydrate resource.

- Several development scenarios have been used to address the key objectives of this analysis. To illustrate key assumptions and uncertainties, simplified scenarios using fixed methane values and scales of development have been assumed. These are then combined into a composite scenario which illustrates a staged development pattern which is most likely given the technical uncertainties surrounding hydrate exploitation. The use of the simplified scenarios does not alter the conclusions which can be drawn from the analysis.
- Where possible, the assumption used in MED's New Zealand Energy Strategy are incorporated into the analysis. The most significant of these are the US$/NZ$ exchange rate of 0.54, an oil price of US$60/bbl and a 5% discount rate. Variants of these are tested in the sensitivity analysis. In addition, the LNG price formulae developed by Gary Eng and published on the MED website are used as the basis for the international price of methane.
- The national economic analysis excludes all internal transfers such as taxation and payments between the commercial entities involved in the projects. Economic costs and benefits throughout the project life are in real 2008 New Zealand dollars and currency exchange rates are assumed to remain constant.
- Gas hydrate technology is in its infancy with no commercial developments made. Development cost estimates have been prepared by Transfield Worley Services based on the subsea gas well technology described by Steven Hancock at the New Zealand Petroleum conference 2008. Transfield Worley's cost estimates are very close to those of Hancock for developments in the capacity range of 150 to 300 PJ. These estimates probably reflect the most advanced gas hydrate research

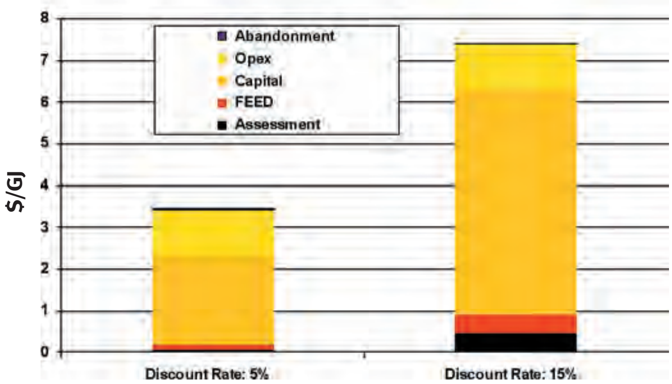


Figure 1: 300 PJ Hydrate Development

and Hancock's also provide a useful comparison with natural gas development costs. However, because of there is no commercial precedent upon which to base these hydrate development costs, they are subjected to large variations in the sensitivity analysis.

- Unit costs of production are calculated for both natural gas and gas hydrates. To be consistent with the economic analysis, these have been calculated at a 5% discount rate and are therefore significantly lower than commercial estimates using the same costs of development and operation where a discount rate or cost of capital in the order of 15% would more likely be applied. Figure 1 illustrates the difference in calculated unit cost of production using the same costs but at discount rates of 5% and 15%. The unit cost of production is in effect the unit price the project would have to receive for the methane to achieve an internal rate of return of 5% or 15% on a real dollar, before tax basis.

  Although the project economic analysis is the focus of this study, it is useful also to discuss the commercial context, in particular gas prices and costs of production based on commercial discount rates. As noted, a 15% discount rate is used to replicate commercial costs of capital. It is acknowledged that this figure has been arbitrarily selected but industry views on appropriate costs of capital can vary widely depending on, inter alia, perceived project risk, debt/equity ratios, company risk adversity and the economic and market environment at the time of the analysis and can change from time to time.

- It has been assumed that the availability of gas hydrates will not change the consumption of gas in New Zealand. There is a possibility that gas consumption will increase with the development of a gas hydrate industry particularly if the alternative is imported LNG. However, this analysis has not investigated the price effect on gas consumption and it is assumed that any national benefit arising from higher consumption of gas will be relatively small compared to the benefit arising from reduced gas costs. This assumption will tend to underestimate net benefits somewhat.

2 Development Scenarios

Four scenarios have been chosen to demonstrate the anticipated economics of small and large scale production of gas hydrates and also any benefits of exporting methane:

1. 10 PJ methane/year: feedstock for thermal power (about 200 MW) and/or petrochemicals, requires dissociation of 1.5 million tonnes of hydrate. This size of development is chosen to illustrate the economics of small scale development, where it is likely that hydrates will be competing against indigenous natural gas which is likely to continue to be available in these quantities from new resources for some time to come. It is also used in the composite scenario as the basis for costing the "proving" phase of the staged development.
2. 150 PJ methane/year: equivalent to the whole New Zealand gas market excluding existing methanol capacity, requires dissociation of 22.5 million tonnes of hydrate. In the longer term there is strong possibility that there will be insufficient indigenous natural gas to supply the whole domestic gas market at current rates of consumption with the most likely replacement fuel being imported LNG. This scenario is designed to compare production of hydrates with the importation of LNG.
3. 300 PJ methane/year: equivalent to a total of about 5.4 million tonnes per year of methane split between export as LNG and the supply of the New Zealand gas market, requiring dissociation of 45 million tonnes of hydrate. This scenario illustrates the economics of exporting methane extracted from the hydrate.
4. A composite scenario representing a "most likely" development in which a "proving" project of 10 PJ capacity is developed in anticipation of a major 300 PJ facility to supply the export and domestic markets. This scenario incorporates features of scenarios 1 and 3 with a lead time of eight years between the commencement of production from the two phases of the project assumed.

In the business as usual case for each scenario it is assumed no effort is made to promote the development of New Zealand's hydrate resource in preference to resources in other countries. Under this circumstance it is most probable that New Zealand, because of its small gas market and relative isolation, would receive low priority from potential investors and energy companies and would lag behind the development of hydrates in other larger economies, effectively becoming one of "the last cabs off the rank" with first production not occurring before 2040. Whilst delaying production of hydrates potentially has the advantage of allowing the technology to mature before being used in New Zealand, there are potential economic benefits in accelerating the introduction of the technology, particularly when alternative fuels are significantly more expensive. The impact of bringing forward the first production date of hydrates is examined for each scenario.

3 Benefits and Costs

A number of key assumptions have been made whilst evaluating the various scenarios:

3.1 Value of Methane

The primary economic benefit from producing methane from hydrates will be the cost of supplying the next best alternative fuel. These costs are described for each of the scenarios examined:

- **10 PJ pa scenario:** assumes that there is plentiful indigenous natural gas to supply this relatively small quantity to the domestic market. By displacing natural gas produced from New Zealand fields, the principal economic benefit from the use of hydrate is the avoided cost of producing the natural gas displaced. In effect, this directly compares the costs of producing hydrate and natural gas, with the cheaper being economically more favourable. A cost of production for natural gas is assumed to be $ 2.50/GJ throughout this scenario (refer Figure 2 below).
- **150 PJ pa scenario:** from about 2018 there is insufficient indigenous natural gas to supply this quantity of gas long term unless there is a new discovery or discoveries adding reserves of a similar scale to the Maui field. Without such discoveries, the value of the hydrate will approach the cost of the fuel which would otherwise replace indigenous gas. This fuel is most likely to be imported LNG and the relevant value of methane is the CIF price of LNG plus the cost of regasification in New Zealand. This value is maintained constant throughout this scenario.
- **300 PJ pa scenario:** follows the same assumptions as the 150 PJ except that the additional methane produced will be exported as LNG. The exported methane will compete with LNG in the international market and the ex hydrate plant price for exported hydrate is the LNG FOB price less the liquefaction costs in New Zealand. LNG FOB prices are directly linked to LNG CIF prices by the differential of the ocean freight to the export market, which is most likely to be in East Asia. The determination of the CIF and FOB prices is shown in Table 1. These are kept constant throughout this scenario.
- **Composite scenario:** the same assumptions used to value methane in the other three scenarios are used in the composite scenario. However, unlike the other scenarios, the value of methane consumed in the domestic market is not kept constant and is increased over time from that used in the 10 PJ scenario for the replacement of indigenous gas to that used for the replacement of imported LNG in the other scenarios. Methane values are assumed to ramp up from cost of indigenous gas production in 2015 and reach parity with imported LNG prices in 2020. The value of exported methane remains constant as in the 300 PJ scenario as it is dependent on the price of LNG.

The 150 PJ scenario represents existing New Zealand natural gas consumption with some allowance for growth but excludes gas used for methanol production which is unlikely to be profitable in New Zealand in the longer term unless methanol prices such as those experienced in 2008 are sustained. The remaining gas consumption is split more or less evenly between electricity generation and the combined residential, commercial and industrial (including cogeneration) markets. In practice it is probable that gas consumption will reduce as its price increases when imported as LNG or produced from gas hydrate due to its price elasticity and substitution by cheaper energy forms in the domestic market. The size of this reduction is a complex determination and beyond the scope of this study and will depend on the future prices of competing energy forms and the technical substitutability of gas in each of the four energy market sectors noted above. Using LNG imports as the shadow price will therefore overstate somewhat the value of gas hydrates in the domestic market as some gas probably can be replaced by cheaper indigenous energy forms.

This same volume and price uncertainty does not exist for the export of gas hydrate as the international LNG market will be large compared to New Zealand export quantities and the prices relatively inelastic within each scenario, strengthening the value of adding export capacity to a New Zealand hydrate project, both as a potentially viable investment and providing an anchor load to support the development of the fragmented domestic market.

3.2 LNG Prices

LNG Imports: CIF Price

The CIF price of LNG in New Zealand is determined using the formulae contained in the reports by Gary Eng posted on the MED website[1]. In both reports the New Zealand price is based on the CIF price in Japan on the premise that delivery distances from the point of origin to Japan and New Zealand are similar. Both link the price of LNG linearly with that of crude oil but contain different coefficients, reflecting the respective market conditions at the time the reports were prepared:

- The 2008 formula reflects the Japanese LNG price over the last two or three years where prices were strongly linked to crude oil prices as a result of strong demand over supply. It is also similar to the longer term linear correlation between LNG and crude oil prices, producing an LNG price about 13% higher that that determined by the latter with oil set at US$ 60/barrel.
- The 2006 formula was set when there was effectively a buyers' market, with an overhang of potential sources of LNG supply. At that time the Guangdong LNG contract had been signed with prices significantly lower than traditional Japanese prices and was thought to foreshadow future LNG prices with a weaker link to oil prices. The so-called Guangdong formula used in the 2006 report produced LNG prices about 60% of that derived from historic relationships at US$ 60/barrel. However, this trend to lower prices proved to be short-lived with LNG prices moving back to historical trends as the market reverted more to suppliers' favour.

Whilst the 2008, or "current", formula more accurately reflects recent and historic trends in LNG prices and is a logical basis for predicting future prices, it is probably near the potential upper level of the LNG price range in terms of thermal equivalence to crude oil. Historically the Japanese LNG prices have been high compared to gas in other markets because of, inter alia, the cost of the LNG supply chain, the particular behaviour of the Japanese buyers in favouring indexation to crude oil, and the non-existence of competing gas supplies. Gas-on-gas competition is a major factor in the US market and to a lesser extent in Europe in setting prices, including imported LNG, resulting in gas prices which usually are lower and often more volatile than Japanese prices.

The advent of significant quantities of gas produced from hydrates raises the potential for downward pressure on LNG prices, necessitating a lower price boundary for this analysis. Based on the cost assumptions used in the analysis below, LNG priced using the "current" formula and an oil price of US$ 60/barrel results in very high rates of return to investors in hydrates, suggesting there will be potential to reduce gas prices. Whilst the Guangdong` formula is based on a one-off event, it provides a tangible example of regional LNG pricing under downward pricing pressure from other sources of gas. In the current pricing environment, it is an outlook of relatively low probability and therefore represents a suitably conservative lower bound for LNG prices.

Both the current and Guangdong formulae include the cost of regasifying the LNG in New Zealand and have as their principal independent variables the US$/NZ$ exchange rate and international oil price. These are set at 0.54 and US$60/barrel respectively, both these variables being tested in the sensitivity analysis.

1 1/ A Formula for LNG Pricing, Gary Eng, A report prepared for the Ministry of Economic Development, May 2006; 2/ A Formula for LNG Pricing – An Update, Gary Eng, November 2008

Exchange Rate US$/NZ$	0.54		
Oil Price US$/bbl	60.00		
LNG Price Formula		Guandong	Current
LNG: *CIF*			
LNG Import Price CIF*		9.10	16.77
plus Regasification	1.25	2.31	2.31
Imported gas into network		11.41	19.08
LNG: *FOB*		0.00	0.00
East Asia CIF Price		9.10	16.77
less Freight NZ to East Asia	0.80	1.48	1.48
less Liquefaction Costs	0.80	1.48	1.48
Exports ex hydrate plant		6.13	13.80

** Determined by MED formula*

Table 1: Methane Values Determined from LNG Prices

LNG Exports: FOB Price

Methane produced from hydrates and exported to international markets will be shipped out of New Zealand as LNG. The value of this methane to the hydrate project is the FOB price of the LNG less the cost of liquefying the methane. As New Zealand LNG is likely to be shipped to the large East Asian markets, the FOB price in New Zealand will be the East Asian CIF price less the freight from New Zealand to East Asia. It is also assumed that the CIF price of LNG in New Zealand will be similar to that in East Asia as the transport distances from likely producers will be of a similar magnitude, making the New Zealand FOB price equal to the CIF price less the ocean transport to East Asia. This transport cost has been set at US$ 0.8/GJ, the same as the cost of liquefaction.

3.3 Costs of Production

Principal economic costs are the expenditure on the development of technology, appraisal of the hydrate resource and all capital and operating costs throughout the life of the hydrate plant. For the purposes of this analysis, it is assumed that the project is carbon neutral as the methane from the hydrate replaces natural gas or LNG which have similar carbon and energy contents. It is certain that there will be emissions during the production of the hydrate but no authoritative estimate is available. However, there will be emissions from the production of LNG and natural gas which will to some extent offset those from hydrates.

Hancock has estimated capital and operating costs for 195 PJ per annum hydrate and natural gas developments, providing an insight into the relativity between hydrate and natural gas costs of production. These are complemented by the estimates of Transfield Worley specifically for the 10 PJ and 150 PJ hydrate scenarios whilst the 300 PJ scenario can be considered a near-duplicate of the 150 PJ scenario. As noted, the estimates of Hancock and Worley Transfield are very similar after making due allowance for the differences in project scale. Consequently only one cost estimate is used for each of the the 150 PJ and 300 PJ scenarios.

Two cases have been taken for the 10PJ “proof of concept” scenario:

- **Scenario 10 PJ/C:** Transfield Worley’s estimate which includes a single cluster of 6 wells compared to the 150PJ scenario where an additional 4 clusters would be needed. Otherwise the 10 PJ scenario is considered to be a precursor to the 150 PJ scenario with a single offshore gathering station and onshore facilities sized accordingly. This case represents a likely scenario for a staged commercial 150/300 PJ development with provision to initially prove the technology in a 10 PJ development. Capital expenditure would be disproportionately weighted in the front-end 10 PJ phase.
- **Scenario 10 PJ/S:** A lower cost 10 PJ scenario in which the project is not designed to be integrated into a future, larger development. The overall capital costs will be significantly lower as processing and compression plant can be

sized for the smaller output. This represents a stand-alone "scientific" proof of concept project, designed without cognizance of integration into future capacity expansion.

Table 2 summarises the cost data developed by Hancock and the costs derived from it for each of the scenarios. Five consecutive categories of cost have been included in the analysis:

- Assessment: Includes the development of the hydrate extraction technology and the characterization of the hydrate resource. This expenditure is made over a ten year period prior to the commencement of engineering design.
- FEED: Set at 3% to 5% of capital costs, which is typical of large capital projects and takes place over a three year period for the 150 and 300 PJ scenarios, two years for the 10 PJ/C scenario and one year for the 10 PJ/S scenario.
- Capital: Provided by Transfield Worley and Hancock. Construction times of four years for the 150 and 300 PJ scenarios, three years for the 10 PJ/C and two years for the 10 PJ/S scenario are assumed.
- Operating: Set at 4% to 7% which is consistent with Hancock's lump sum operating costs over a 25 year operating period.
- Abandonment: Set at 5% of capital costs in the year immediately after the last year of operation.

Each of the 10PJ/C and 10 PJ/S scenarios have been included as the forerunner to the 300 PJ development in the composite scenario. Costs and hydrate production profiles are treated somewhat differently in each case:

- As the 10PJ/S scenario is designed to be a "scientific" project, it will not be scaled for integration into the subsequent design of the expanded 300 PJ development. Consequently the total capital cost of the 10 PJ/S composite scenario will be $370 million during the first phase plus $8,391million in the second phase. Conversely, the 10 PJ/C development is designed to be integrated into the final development so the total capital cost will be $8,391 million, comprising $1,300 million in the first phase and $7,091million in the second.
- The construction time for the 300 PJ plant is reduced to three from four years when preceded by the 10 PJ/C development because of the high level of integration with the initial phase. A four year construction period for the 300 PJ facility is assumed with the 10 PJ/S initial phase.
- Hydrate production in the 10 PJ/C case will continue throughout the eight year period prior to the start-up of the 300 PJ plant as the initial phase has been designed for subsequent commercial development. However, hydrate production in the 10PJ/S "scientific" case is assumed to cease after two years, although subsequent production from the 300 PJ plant will also commence eight years after first production from the 10 PJ plant.

Unit costs of methane and gas production under these assumptions are shown in Figure 2 for both hydrate-derived methane and natural gas. As discussed in Section 1, the costs determined at a 5% discount rate represent the economic costs of production used in this analysis whereas those at 15% are indicative of commercial prices.

	NZ$ Million			
Scenario (PJ)	10S	10C	150	300
Hydrate				
Assessment*	22	22	66	168
FEED	14	44	132	420
Capex	370	1300	4043	8391
Opex pa	17	81	280	332
Abandonment	19	65	202	420
Gas				
Assessment			43	86
FEED			107	214
Capex			2142	4284
Opex pa			102	205

Table 2: Costs of Exploiting Hydrate Resource

4 Competitiveness of Hydrates with Alternative Sources of Gas

Economic internal rate of return is used to measure the net benefit of avoiding the cost of natural gas supply by investment in hydrate technology development and subsequent hydrate plant capital and operations. This is summarized in Table 3 for the 10, 150 and 300 PJ per annum scenarios

Based on the base case assumptions used in this analysis, some key conclusions can be drawn:

- Hydrate production results in significant net economic benefits relative to imported gas. Gas is valued against LNG in both the 150 and 300 PJ scenarios, resulting in economic internal rates of return of 30.1% and 26.9% respectively when using the current formula for LNG prices. The driver behind these high returns is the high value of LNG imports and exports ($19.08/GJ and $13.80/GJ respectively) relative to the cost of producing methane from hydrate ($4.09/GJ $3.47/GJ).
- The economic benefits remain substantial when the LNG is priced according to the Guandong formula with IRR's of 21.5% and 17.4% for the two scenarios, indicating hydrate production can withstand significant downward pressure on regional LNG prices under base case assumptions.
- Hydrates are unlikely to be competitive with domestic natural gas. Both 10 PJ scenarios have negative internal rates of return as the cost of production of hydrate will most probably be significantly more than that of natural gas. This scenario corresponds to the situation where there is plentiful indigenous gas to meet the same demand requirement to be supplied by hydrate and will equally apply to the larger scenarios if large new, low cost gas reserves were to be discovered. In these circumstances, an acceptable rate of return might be attained if part of the hydrate output was directed to exports because of relatively high LNG-related price received, as illustrated in the sensitivities section of Table 3 where gas value is set at domestic levels.

Table 3 also shows the sensitivity of economic rate of return to changes in some of the base case assumptions used in the analysis. Even when taking large variations in the principal inputs of project costs, oil price and exchange rate, the internal rate of return remains above 5% for the scenarios predicated on LNG prices, indicating there is significant margin in the project to absorb adverse shifts in the conditions underlying development:

- At an oil price of US$20 per barrel and correspondingly low LNG prices, the internal rate of return remains at or in excess of 10% for both the 150 and 300 PJ scenarios under both LNG pricing formulae. Given recent history, it is improbable that a long term oil price below this level would be sustained, suggesting that a hydrate project replacing LNG imports will provide economic benefits under most oil and LNG pricing outlooks, provided the base case assumptions for project costs remain sound.
- Similarly, internal rate of return will remain above 10% if the exchange rate were to be increased to 0.85, slightly above

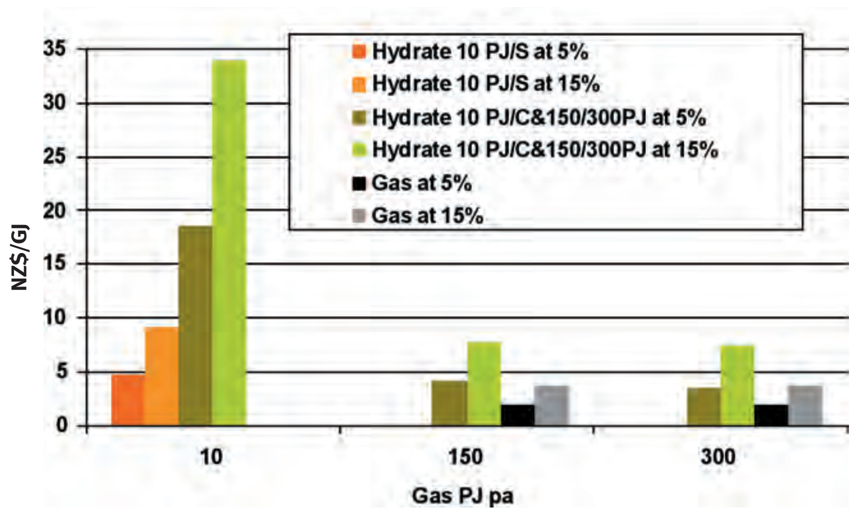


Figure 2: Unit Costs of Methane and Gas Production at Different Discount Rates

Scenario Size (PJ)	300		150		10 C	10 S
Export Component (PJ)	150		0		0	
Gas Value Basis	LNG		LNG		Domestic	
Cost of Production ($/GJ)	3.47		4.09		18.54	4.76
LNG Price Formula	Guandong	Current	Guandong	Guandong	Guandong	Guandong
Internal Rates of Return (IRR)						
Base Case Assumptions	17.4%	26.9%	21.5%	30.1%	Negative	Negative
Sensitivities						
Development Costs + 100%	8.0%	16.5%	10.2%	18.5%	Negative	Negative
Domestic Gas Cost: $5/GJ	17.4%	26.9%	21.5%	30.1%	Negative	Negative
Oil Price: USD$20/bbl	10.0%	12.7%	15.1%	17.3%	Negative	Negative
Exchange Rate US$/NZ$: 0.85	11.1%	20.0%	14.0%	22.5%	Negative	Negative
Gas Value: Domestic	7.8%	16.3%	Negative	Negative	Negative	Negative

Table 3: Replacement of Gas by Hydrates: Internal Rates of Return

the highest rate experienced in the last 20 years, which effectively reduces the benefit obtained from replacing US dollar denominated LNG. A combination of this high exchange rate and US$20/barrel oil would reduce IRR's to 6.7% and 10.1% for the 300 and 150 PJ scenarios respectively, or 4.2% and 7.9% using the Guandong formula. However, this combination is counter-intuitive as a weak US dollar is generally associated with higher prices for US dollar denominated commodities such as oil.

- Doubling the project costs will reduce economic IRR's to 16.5% and 18.5% (8.0% and 10.2% using the Guandong formula) for the 300 and 150 PJ scenarios, indicating the project is robust relative to the assumptions on capital and operating costs. However, whilst they are considered conservatively high at this time, the hydrate costs are based unproven technology and the non-existence of any commercial development. At doubled project costs, the 5% economic IRR threshold is reached when the oil price is reduced to US$ 22.6/barrel for the 300 PJ scenario and US$ 17.1/barrel for the 150 PJ scenario (US$ 39.9/barrel and US$ 24.6/barrel using the Guandong formula), suggesting the hydrate development will be economically attractive under most cost and oil price outlooks. It also emphasizes the importance of accelerating investigations into hydrate technology development to reduce uncertainties regarding project costs. The impact of oil prices on hydrate project economics is discussed in more detail in Section 5.
- In the 10 PJ scenarios, the 5% economic threshold is met only with domestic gas prices at $18.5/GJ and $4.8/GJ for the 10 PJ/C and 10 PJ/S scenarios. These would have to be nearly doubled to result in a commercial level IRR of 15%, indicating it is highly unlikely that hydrates would compete with domestic gas resources. Only the 10 PJ/S scenario would be competitive with imported LNG under the BAU criteria, even with doubled project costs, but this does not represent a long-term commercial case.

5 Impact of Hydrates on International Gas Prices

Whilst oil price is the primary energy price variable used in this analysis, it is the LNG price derived from it that directly influences the hydrate project's economic performance. The relationship between LNG price and project IRR is independent of the two LNG price formulae discussed in Section 3.2 and is shown in Figure 3 for the base case and also with project costs escalated 100% to reflect the general uncertainty surrounding project costs.

Even with double the base case costs, the hydrate project will meet the government criterion of 5% IRR at an LNG price of less than $ 8.0/GJ CIF, with the requisite LNG price ranging from $ 1.6/GJ for the 150 PJ scenario to $ 7.3/GJ for the 300 PJ scenario with costs escalated 100%. These LNG prices are below those determined by both the current and Guandong price formulae which are shown in

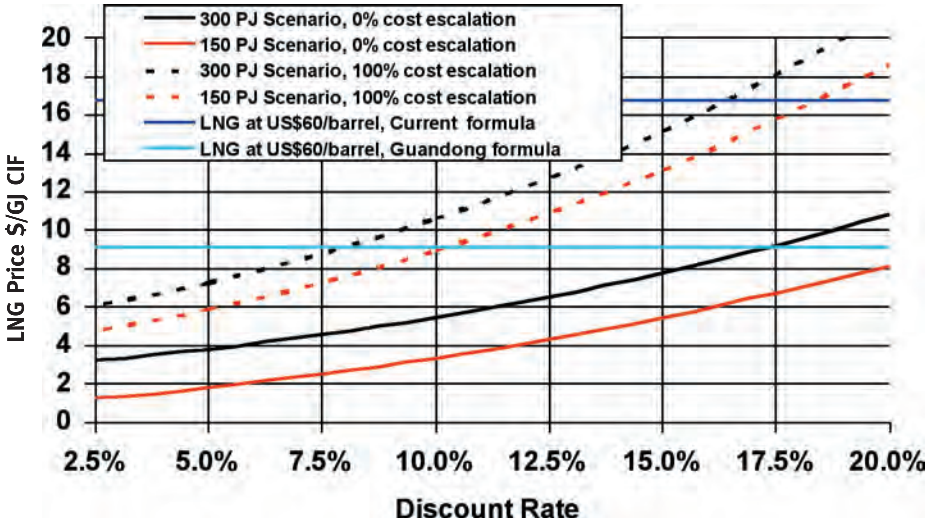


Figure 3: The linkage between crude oil prices and hydrate project IRR under the two LNG pricing formulae

Figure 3 at $ 16.77/GJ and $ 9.10/GJ at the base case oil price of US$ 60/barrel.

Gas produced from hydrate and sold into the market will have to be priced significantly higher to meet a commercial IRR criterion of 15%[2]. Figure 3 illustrates that this criterion is generally met at base case project costs when the gas market price is based on the Guandong LNG price formula: gas priced to the Guandong formula results in a project IRR in excess of 20% and 17.0% for the 150 PJ and 300 PJ scenarios respectively. Only with the project costs doubled will the requisite gas market price approach the price determined by the current formula. It follows, therefore, that there is scope for downward movement of LNG market prices relative to crude oil from current levels should gas from hydrate production enter the international gas market. This will be less apparent at lower oil prices and with escalated hydrate project costs.

2 Assuming that domestic prices of gas rise to meet that of LNG. This may be an optimistic assumption if indigenous hydrate gas is produced rather than LNG imported as is the case at present where domestic gas prices are lower than potential LNG imports.

Figure 4 shows the linkage between crude oil prices and hydrate project IRR under the two LNG pricing formulae, representing high and low relativities between LNG and oil prices.

Some general conclusions can be drawn from this analysis which attest to the economic potential of gas hydrates:

- When LNG price is the basis for gas hydrate value, the government criterion of 5% IRR

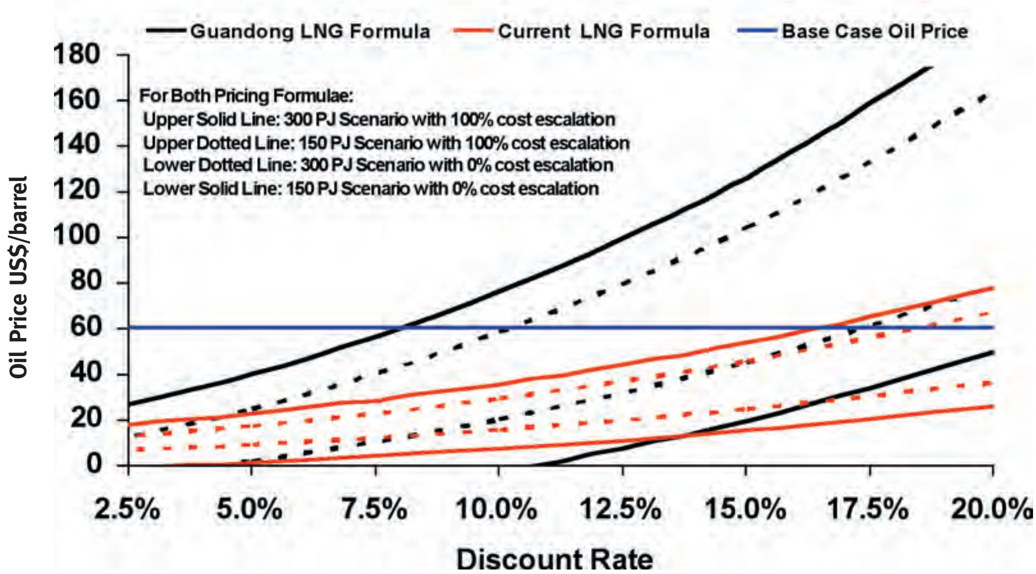


Figure 4 above illustrates the linkage between oil price and project internal rates of return is met in all base case project scenarios, including the doubling of project costs and both high and low LNG price relativities with oil. This applies to oil prices as low as US$ 40/barrel, significantly below the official outlook of US$ 60/barrel.

- A commercial criterion of 15% IRR will be met at an oil price of US$ 60/barrel in all scenarios with the exception of a combination of low LNG prices relative to oil (when applying the Guandong formula) and escalated project costs, providing potential for hydrate producers to undercut LNG priced at current relativities with crude oil. This becomes more pronounced at oil prices above US$ 60/barrel and vice versa.

6 Benefits of Accelerating Hydrate Development

Under business as usual development conditions, the New Zealand government provides no assistance or incentive to develop indigenous hydrate resources, with first production assumed to occur in 2040 because of low priority given to New Zealand by investors and energy companies. This section evaluates the impact of bringing forward the date of first hydrate production through government assistance such as expenditure during the evaluation of the hydrate resource and technology or some type of tax incentives. The following simplifying assumptions have been used:

- Any expenditure made by government replaces expenditure by the private sector. As this is an economic analysis, such internal transfers are not included and so the expenditure profile is assumed to remain the same. Similarly, tax incentives are internal transfers and will not affect the project cash flow.
- The analysis has been undertaken only for the 10, 150 and 300 PJ scenarios, each subject to constant gas values, to illustrate the impact of bringing project implementation forward. The same conclusions drawn from these three scenarios will be applicable to the composite scenario discussed below.
- Two cases are analysed for each scenario: bringing first production forward ten years to 2030 and bringing it forward twenty years to 2020, the latter being the very earliest hydrate technology could be brought onstream under ideal circumstances. In all cases, the same implementation schedule is assumed to hold, ie the lead times for assessment, FEED, construction, operations and abandonment will remain constant with each being brought forward either ten or twenty years. The only exception is the assessment costs in the 2020 start up case where these must be spent over a five year rather than ten year period to meet the implementation schedule. This has a virtually negligible impact on the analysis.

For each of the three scenarios the economic internal rate of return and cost of hydrate production are the same for the business as usual, 2030 start up and 2020 start up cases as the relative investment and production profiles are unchanged despite the different start up dates. The output principally affected by the different start up dates will be the project economic net present value due to the effect of the time value of money. This is illustrated in Figures 5 a and b which show the relative discounted costs of supplying gas either as LNG or hydrate to the New Zealand market over the period 2009 to 2075 for the 300 PJ scenario:

- In each figure the blue line shows the discounted annual cost for the business as usual case of supplying gas over this period either as imported LNG or hydrate.
- Whilst the domestic market is being supplied with LNG, the annual costs will be a combination of imported LNG costs plus the costs of hydrate assessment, FEED, capital and abandonment as the hydrate project is being developed or abandoned.
- Whilst hydrate is being produced the annual cost will be the hydrate operating cost, offset in this scenario by the income from the export of LNG, hence a “negative” cost during this period.
- Similarly the red line shows the discounted annual costs when the hydrate project is brought forward ten or twenty years. These figures will be larger than the business as usual case due to the effect of discounting.
- The broken black line is the difference in discounted annual cost (negative being more costly) between the business as usual case and the brought forward cases. The sum of these annual costs (or the area

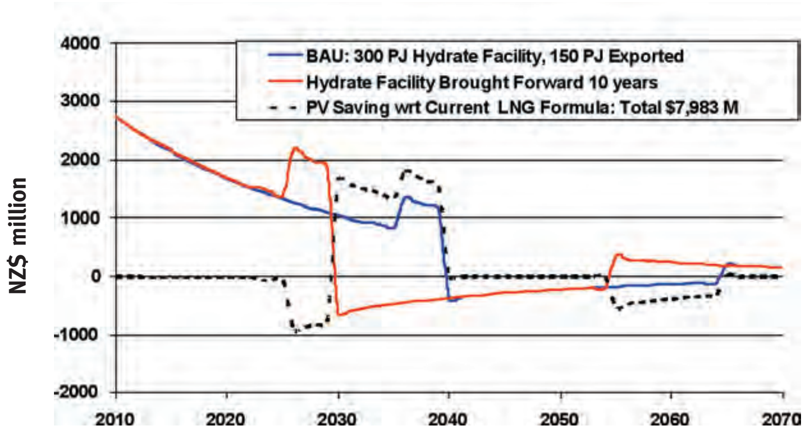


Figure 5a: Economic impact of accelerating project by 10 years

under the broken line) is the reduction in total present cost of gas supply by bringing the project forward. In the 300 PJ case this reduction is $21,012 million for the 2020 start up case and $7,983 million for 2030 start up over the 67 year period and is equivalent to the increase in net present value of the hydrate project compared to gas supply.

Following this same methodology, the long term reduction in net present costs of gas supply by bringing forward the start date of hydrate production is summarized for the three scenarios in Table 5.

This analysis indicates there is significant potential to reduce the longer term cost of supplying gas to the New Zealand market and improve hydrate project economics if Government implements policy directed at accelerating the development of hydrate resources.

- Under base case assumptions, the net present cost of gas supply by hydrate could be up to about 25% lower over a 65+ year period if the start of hydrate production is brought forward from 2040 to 2020. This saving could be increased towards half with LNG exports included in the hydrate development.
- This benefit falls significantly as the hydrate project is delayed back toward the BAU timeline, the saving in net present cost reducing nearly two thirds if hydrate production is delayed back from 2020 to 2030.
- A possible additional benefit of early implementation is an early period of higher gas prices should a subsequent widespread uptake of hydrate production place downward pressure on international LNG prices.
- This same benefit will not apply when displacing low cost indigenous natural

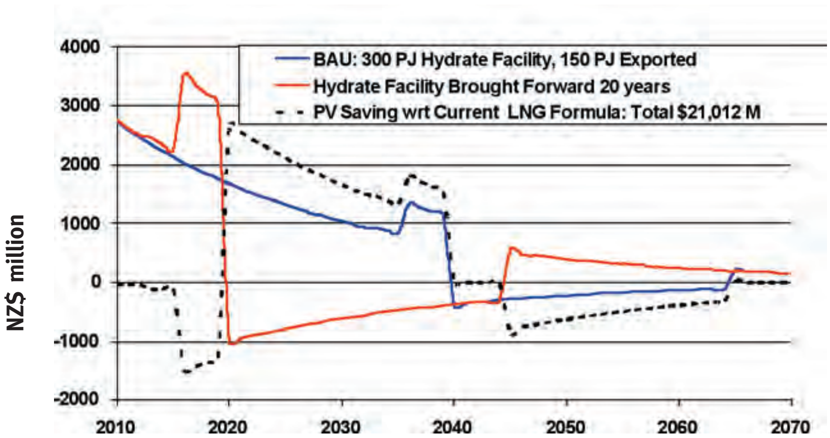


Figure 5b: Economic impact of accelerating project by 20 years

Gas Supply from 2009 to 2075						
Scenario Size (PJ)	**300**		**150**		**10C**	**10S**
Exports (PJ)	150		0		0	0
Gas Value	LNG		LNG		Domestic	
LNG Price Formula	Guandong	Current	Guandong	Current		
Hydrate Project Life (years)	25	25	25	25	25	25
BAU Total Present Cost $M*	-29388	-45129	-30994	-50489	-1028	-579
Hydrate Production Start Date	**Reduction in Total Present Cost $M**					
2040	0	0	0	0	0	0
2030	3263	7983	2252	4612	-329	-46
2020	8604	21012	5931	12135	-863	-121
** Discount rate of 5%*						

Table 5: Reduction in Present Cost of Gas Supply

gas as illustrated in the 10 PJ scenario. As shown in Section 4, the business as usual IRR, and hence net present value, for this scenario is negative. Under these circumstances bringing forward the start of hydrate production will increase the net present cost of gas rather than reduce it.

7 Addition of Export Capacity to Hydrate Development

The internal rate of return from the development of 300 PJ hydrate scenario in which both the domestic and export gas markets are supplied is less that that for the 150 PJ scenario where only the domestic gas market is supplied (see Table 3). This is due to the lower economic value of methane sent to the liquefaction plant for export compared to that of imported LNG used to supply the domestic market.

Based on the differential between the net cash flows of the two scenarios, the internal rate of return for the marginal hydrate production capacity used for methane exports is 23.8% under base case assumptions and current price relativities between oil and LNG or 13.2% when the Guandong formula for LNG prices is used. Oil price, as the principal determinant of LNG price, is a key sensitivity: a 5% marginal economic internal rate of return is achieved for the plant export capacity at an oil price of US$ 16.9/barrel and US$ 28.1/barrel if the costs of hydrate development were to be doubled (US$ 24.0/barrel and US$ 55.2/barrel respectively when using the Guandong formula).

This analysis suggests that there is potential economic merit in exporting methane from hydrates, even with the base case project costs doubled, although this is less than using the gas hydrate in the domestic market. Should LNG prices be depressed relative to oil prices, as prescribed by the Guandong formula, then the economic benefits are less obvious if project costs increase. However, this simple analysis does not recognize some potential benefits of adding export capacity to a hydrate development:

- By expanding the production capacity to accommodate exports, there is potential to reduce unit costs of production through economies of scale for capital and resource and technology assessment costs. This potential has been explicitly excluded from the analysis for lack of relevant cost data.
- An export LNG market underpinned by a long term sales and purchase contract could provide a substantial anchor load to help secure financing for the hydrate project. It is probable that the introduction of hydrate supplies into the domestic gas market will be more fragmented and protracted because of the existence of natural gas or future LNG supply contracts. This is illustrated in Figure 6 for the current gas supply outlook based on known indigenous gas reserves.
- There are no technical problems foreseen in the liquefaction of methane derived from hydrates. LNG liquefaction and transportation technology is well established and widely used on a commercial basis.

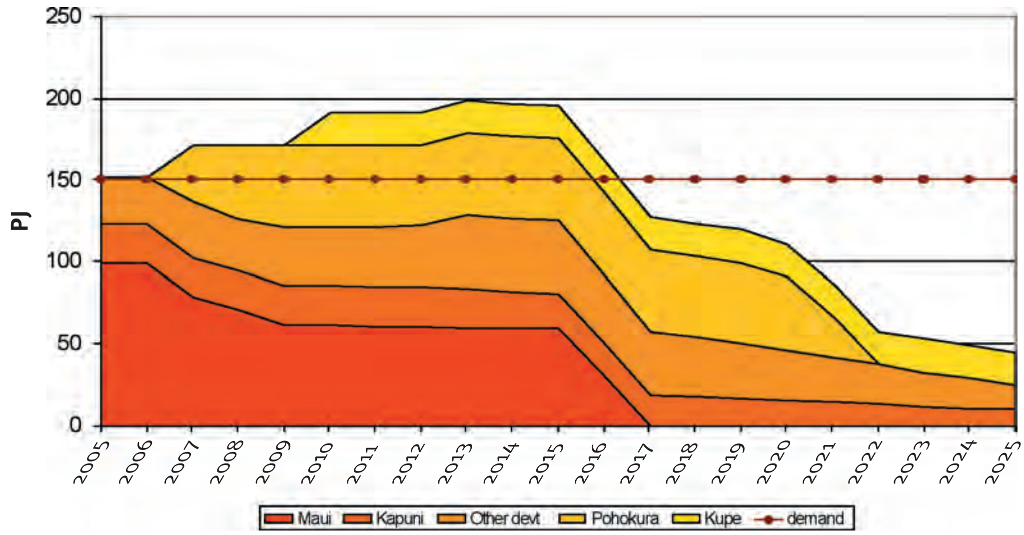


Figure 6: NZ Gas Supply Outlook to 2025

- If hydrates have to compete against plentiful supplies of indigenous natural gas (a 10 PJ type scenario), exports have the potential to improve economic benefits from the project as the value of methane exported is higher than the value of replacing indigenous natural gas production. This is illustrated in the sensitivity section of Table 3 where hydrate supplied to the New Zealand market is valued at the cost of domestic gas production.

In a commercial context the prospect for exporting hydrate as LNG is not as favourable as indicated by the economic analysis. The inputs to a commercial financial analysis of the marginal hydrate exported will be similar to those used in the economic analysis as the methane has been valued against international LNG prices and project costs effectively will be the same, although not necessarily all born by the project developer. A before tax internal rate of return of 13% may not be sufficient for developers.

8. Composite Scenario

The composite scenario has been included to illustrate a situation where investment is made in a 10 PJ "proof of concept" development in advance of the main project to develop technology experience and to gain acceptance for the product in the New Zealand gas market. Key features of this analysis are:

- Both the 10 PJ/C and 10 PJ/S scenarios are considered to illustrate the cash flow implications of each. This level of

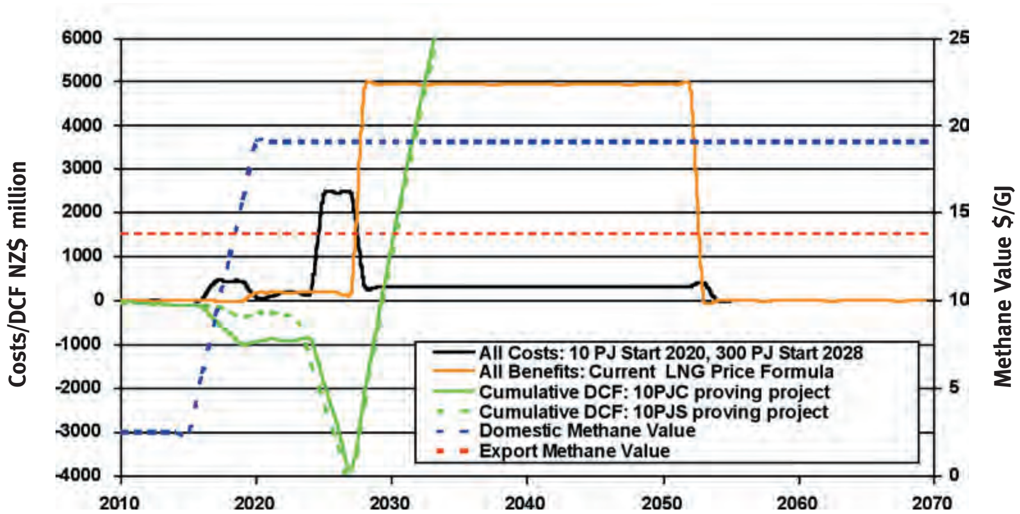


Figure 7: Discounted Cashflows for the Composite (staged) Hydrate Development: 10 PJ/C and 300 PJ, 5% discount rate.

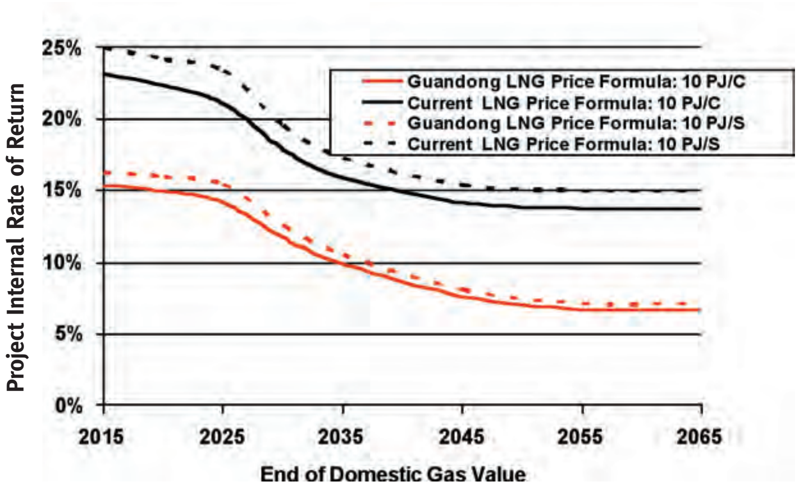


Figure 8: Delay to End Date of Domestic Gas Value

production should find a market relatively easily, for example at a typically sized CCGT power plant.

- Production is expanded to 300 PJ eight years after first production, providing time for technology and market development. It is sized to meet the whole New Zealand gas market and to provide an anchor load to the export market. The assessment, FEED and construction schedules for both the 10 PJ and 300 PJ are assumed to be the same as those in the set out in Table 2.
- Exported methane is valued as in the 300 PJ scenario. Methane sold into the domestic market is valued against the replacement of indigenous gas until 2015 and then ramped up to parity with imported LNG prices in 2020 and held constant thereafter.

Cash flow and methane value profiles for the composite scenario are shown in Figure 7.

- The economic benefits of the composite scenario are dominated by the performance of the second phase of the project whose income and expenditure dwarfs those of the 10 PJ proving development. This is particularly the case when the proving development costs are those used for the 10 PJ/S scenario which are only 6% of the cost of the total 300 PJ development. As illustrated in Table 6, the difference in the internal rates of return for the composite scenario with the 10 PJ/S initial development and the 300 PJ scenario is less than 2%. This difference is largely due to the cessation of hydrate production after two years during the first 10 PJ phase of development.
- If the investment schedule follows that of the 10 PJ/C scenario, the difference in IRR between the composite and 300 PJ scenarios widens. In this case the capital cost of the proving project is 15% of the total and the

Scenario	**Composite / 10C**		**Composite / 10S**		**300 PJ**	
LNG Price Formula	Guandong	Current	Guandong	Current	Guandong	Current
Cost of Production $/GJ	3.67		3.60		3.47	
Internal Rate of Return						
Base Case Assumptions	15.4%	23.2%	16.3%	25.0%	17.4%	26.9%
Sensitivities						
Development Costs +100%	7.1%	14.5%	7.4%	15.4%	8.0%	16.5%
Domestic Gas Cost $5.00 $/GJ	15.4%	23.2%	16.3%	25.0%	17.4%	26.9%
Oil Price 20 US$/bbl	9.0%	11.3%	9.4%	11.9%	10.0%	12.7%
Exchange Rate US$/NZ$ 0.85	9.9%	17.4%	10.4%	18.6%	11.1%	20.0%
Gas Value: Domestic	6.7%	13.7%	7.1%	15%	7.8%	16.3%

Table 6: Composite and 300 PJ Scenarios: Internal Rates of Return

disproportionately high capital costs during this initial project phase will reduce project rates of return compared to the 10 PJ/S scenario even though hydrate production is maintained throughout the initial project phase. Nevertheless, the internal rates of return for the 10 PJ/C scenario remain above the economic benchmark.

- Delay to the onset of valuing hydrate sold into the New Zealand market against imported LNG will progressively reduce project IRR. This will occur if significant new indigenous natural gas reserves are discovered and the valuation of hydrate against the replacement of indigenous gas persists beyond 2015. The impact of this delay on project IRR is shown in Figure 8.
- At a commercial discount rate of 15%, a positive project net present value will not be attained during the proving phase prior to investing in the larger, second phase of the project, indicating that investors may not recover their capital for a sustained period with a staged development of this type. This applies for both the 10 PJ/C and 10 PJ/S scenarios. Similarly, when using a 5% discount rate, net economic benefits will not accrue during the initial project phase, in the case of the 10 PJ/S scenario due to the cessation of hydrate production after two years (see Figure 7).
- The staged development will reduce technology risk by limiting capital expenditure to the small scale project whilst the hydrate technology is being developed.
- Similarly, the staged development will reduce market risk. Output from the 10 PJ proving phase should be relatively easy to balance with market demand. Larger developments, as illustrated in the 150 PJ scenario, may offer greater economic benefits but face a more challenging and protracted effort to sell their full capacity on the domestic market. Inclusion of export capacity in the latter 300 PJ phase will provide flexibility and anchor demand during the ramp up of the domestic market. Whilst this could result in risk of stranding methane liquefaction capacity, it is probable the hydrate mining could be expanded to match.

9 General Conclusions

Gas hydrates offer a real opportunity to make a significant contribution to New Zealand's longer term energy requirements with large deposits identified close to the North Island coast and within relatively easy access of existing natural gas infrastructure. Based on the best information currently available, this analysis indicates that the use of hydrates potentially will bring economic benefits to New Zealand and these can be increased by policy directed at accelerating their development. The key findings of this analysis are summarized:

- Gas hydrates can be produced at significantly lower costs than imported LNG, resulting in economic internal rates of return significantly higher than government guidelines for hydrate developments replacing potential LNG imports. This provides a significant opportunity for hydrates if insufficient reserves of indigenous natural gas are found to meet market requirements. However, it is improbable that hydrates would be competitive with natural gas if sufficient indigenous reserves of gas were to be discovered because of the greater complexity and cost of hydrate production.
- Whilst the use of imported LNG as a shadow economic price might overstate the value of gas hydrates in the domestic energy market, this analysis demonstrates that gas hydrates present a better alternative to LNG should be latter be a commercially viable backstop for dwindling indigenous natural gas reserves.
- Technology for hydrates extraction and processing is in its infancy with no development having been commercialized as yet, placing a high level of uncertainty on the cost estimates used in this analysis. Whilst there is a significant margin between hydrate project economic IRR's and government guidelines based on these estimates, this will diminish should these costs increase, the outlook for oil prices decrease, or LNG prices become depressed through competition with gas hydrates should the uptake of the latter become widespread. Increasing the research effort to understand and prove hydrate technology will reduce this uncertainty, minimize investment risk and help bring forward commercialization of hydrate resources.

- Accelerating the development of hydrates resources as an alternative to imported LNG will significantly reduce the long term economic cost of supplying gas to the New Zealand market. It is important that policy settings are put in place to encourage early investment in New Zealand's hydrate resources otherwise international investors in this technology will preferentially concentrate on other hydrate resources with access to larger and more diverse energy markets.
- Export of hydrate methane as LNG is technically feasible and potentially can reduce market risk for a large scale development by diversifying out of the fragmented New Zealand gas market and help anchor investment through long term export contracts. However, the economic and financial benefits of exports will be lower than competing with LNG in the domestic gas market and will be more sensitive to project costs and the outlook for oil and LNG prices.
- A staged hydrate project development with a small proving project preceding the main development will reduce project risk and help understanding of technical and marketing issues prior to the principal investment in the project. Whilst the second, larger phase will dictate overall project economics and will be attractive if competing against LNG, the proving phase will not be commercially self-supporting. A government policy directed at supporting investment and minimizing investment during the proving phase will facilitate the implementation of any subsequent large scale commercial development.

APPENDIX 8: Gas Hydrates Forward Calendar of Events

2025	Completion of analyses and other data collection activities to assess the potential for expanding the technically recoverable marine hydrate resource beyond permeable sandstone reservoirs to include other, non-sandstone accumulation.	[10]
2020	Large-scale Federal Involvement in US DoE Alaskan North Slope JIP expected to end	[10]
2020	Parameters for Commercial productivity of marine hydrates in Gulf of Mexico understood	[10]
2016	(Japan) Estimated full production start date, corresponding with completion of 16-year test and development programme	[4]
2015	Completion of possible 3rd Alaska North Slope test well	[10]
2015	Confirmation of marine hydrate technical recoverability	[10]
2015	Collection of sufficient data to constrain the rates of methane flux from the sediments to the water column and ultimately, to the atmosphere.	[10]
2012	(Japan) Preparation for Commercial Production: Phase 3 of Japan's Methane Hydrate Exploitation Program	[5]
2012	Initial Production Test in Marine Environment (Gulf of Mexico) beginning, followed closely by second test.	[10]
2011	7th international Conference on Gas Hydrates, Edinbourgh	[1]
2011	New Zealand Petroleum Conference, September 2011 (TBC)	
2011	Fiery Ice Conference, Wellington, May 2011 (TBO)	
2010	Second round of exploratory drilling initiated in Gulf of Mexico	[10]
2010	(US) National Methane Hydrate R&D Program expectes to have developed and tested engineering concepts for production of gas from hydrate deposits	[11]
2009-2013	2nd long-term test well at Alaska North Slope site.	[10]
2009-2010	(Indian)NGHP Expedition 02 may be constituted to drill and log several of the most promising gas hydrate sand-dominated prospects	[3]
30 Sep 2009 (latest)	US Secretary of Energy will report to US Congress on recommendations of the National Research Council into further methane hydrate research and development needs	[7]
10 March 2009	(Japan) JOGMEC Contract for Study of Sand Control for Methane Hydrate formation concludes	[9]
2009	Likely beginning of US DoE/BPAX (BP Alaksa eXploration) methane hydrate production site (location currently under investigation)	[8]
2009	NETL_supported Chevron-Texaco JIP evaluation of three Gulf of Mexico sites for future drilling and coring activities	[12]
2009	(Indian) National Institute of Ocean Technology NIOT to start coring in Krishna-Godavari basin. Vessel " Sagar Nidhi"	[2]
2009	(Korea, US) SK intends in participating in US pilot project at Alaska North Slope	[6]
2008-2011	(German) IFM_GEOMAR "SUGAR" Project to develop Exploration, Production and Transport methane hydrate technologies	[13]
End 2008 – 2010	Completion of the [US] Department of the Interior's (DOI) initial regional assessment of in-place and technically recoverable resources across the broader Alaska North Slope. Assessment informed by min. one well test in Eileen Trend (Prudhoe Bay region). Production test min. 18 months, depressurization + downhole heating.	[10]
End 2008	Initial [US] Department of Interior assessment (MMS and USGS) of scale of marine hydrate resources completed	[10]
End 2008	installation of a gas hydrate sea floor observatory in the Gulf of Mexico	[10]
2007-2011	(Japan) Test drilling scheduled /in Japanese Waters (Nankai Trough)	[4,5]

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APPENDIX 9: CAENZ Strategic Hydrates Initiatives

By contributing to international efforts to assess the commercial feasibility of gas hydrates production New Zealand should be better positioned to take advantage of international development as well as leverage our limited resources to allow the optimal realisation of the economic potential of this strategic resource.

In addition to the scientific collaborations that GNS and NIWA have been heavily involved in, CAENZ has been actively developing and pursuing strategic initiatives to increase the international visibility of both the scientific and research opportunities from the New Zealand gas hydrates resource endowment, as well as the world class capabilities of New Zealand gas hydrates researchers.

These strategic initiatives included:

- CAENZ being tasked by Crown Minerals to bring together a well attended gas hydrates session at the 2008 New Zealand Petroleum Conference in March 2008;
- CAENZ coordinated a series of private briefings on gas hydrates resource development opportunities to politicians and government official in Wellington following the 2008 NZ Petroleum Conference;
- CAENZ being commissioned by Crown Minerals to bring together an Options Analysis for the commercial development for New Zealand's gas hydrates resource;
- CAENZ and GNS Science, jointly bid to host the 2011 International Conference on Gas Hydrates in Wellington at the 2008 ICGH Conference in Vancouver. Although unsuccessful, the bid has significantly raised New Zealand's profile within the wider gas hydrates research community;
- CAENZ hosted two Visiting Fellows in 2008 with the intention of forging closer collaborative relationships with their host organisations – Dr Karen Kozielski from CSIRO, Melbourne in Christchurch in August; and Professor Carolyn Koh, Director of the Gas Hydrates Research Centre at the Colorado School of Mines in Wellington and Christchurch in September;
- CAENZ engaged a Master of Engineering candidate over the 2008 summer holidays as a Gas Hydrates intern. CAENZ will also be supporting up to three final year Chemical and Process Engineering student teams who will be undertaking Design Projects on gas hydrate related engineering problems;
- CAENZ recently hosted Gary Humphreys, Senior Manager Scientific Drilling and Gas Hydrates from Fugro GeoConsulting, Houston in Wellington in February. Gary was the keynote speaker at an invitational seminar on the key findings from a range of recent gas hydrate national programmes, and was also made available to a number of government agencies for private briefings on the subject;
- CAENZ was also approached by the Chevron-led Gulf of Mexico Gas Hydrates Joint Industry Programme to investigate interest in a 'NZ Inc.' participation in the Gulf of Mexico JIP;
- GNS Science and GeoSphere, with support from CAENZ, brought together a preliminary gas hydrates roadmap for development that envisaged a timeframe for commercial production of hydrates in New Zealand by 2020;